Power balancing capacity and biomass demand from flexible district heating production to balance variable renewable power generation

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1. Introduction

The international community has, by ratifying the Paris Agreement, agreed to take common action in order to hamper the greenhouse effect [1]. For instance, the European Commission has announced a “European Green Deal” [2], containing explicit goals to decarbonize energy sectors and increase renewable power. This study investigates to what extent district heating systems with biomass-fueled combined heat and power, electricity driven compression heat pumps, and pit thermal energy storages, can contribute to power balancing capacity in a future Swedish power system with a high share of variable renewable electricity production. District heat production is, in this study, unconventionally controlled to primarily supply a power balancing demand, where co-produced heat is stored if not directly supplied to district heating users. The impact of this on the biomass demand is also investigated. Simulations are made on an aggregated level for one part of the Swedish electricity market. The results show that district heating systems have the potential to reduce peak variable renewable power deficits by up to 52%. All power surpluses can potentially be used for heat production in heat pumps. A heat storage capacity of 17–18% of the heat demand is necessary. Fuel use are 11–12% higher for district heating production controlled for power balancing compared to conventional heat production, depending on the mix of renewable power generation technologies. For instance, a large share of solar power in relation to wind power reduce fuel use to a greater extent when compared to the opposite relation.

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potential for CHP in German DHSs to contribute with controllable power capacity is investigated for scenarios with high shares of VRE.

The studies presented in [7,8,9,10] are examples of how power systems can be integrated with thermal systems to reduce the need for curtailments of VRE surpluses, and to produce power to cover VRE deficits. However, the heat demand level in DHSs, that varies significantly between seasons, is limiting for the possibilities to operate heat pumps and/or CHP units. The maximum heat load in winter in the northern European countries is up to ten [6] times the average heat load in summer. The flexibility of CHP and P2H production can, however, be increased with large-scale thermal energy storages (TES), that can partly decouple heat production from heat demand. This means that heat does not necessarily need to be produced to instantly supply the heat demand. So, as long as heat storage capacity is available, CHP and P2H units can be operated primarily for electricity production and consumption. In [9,10], a TES is shown to, by constituting a flexible heat load, prevent reduced electricity quality from increased VRE production.

If the operation of CHP and heat pumps, in combination with a TES, is coordinated to supply, for example, a power balancing demand, this is a similar system to what in the literature generally is referred to as a virtual power plant (VPP). Typically, VPPs focus on distributed VRE generation and how to perform load shifting via electrical storage, demand-side management, or thermal production via P2H, i.e., operated in a multi-carrier energy system. Considering the growing power demand in urban areas and the ongoing extension of VRE production capacity it is motivated to propose that CHP units should operate to primarily supply an electricity demand rather than a heat demand. It is, however, also of relevance to investigate if a VPP with CHP in combination with heat pumps and heat storages could provide a power balancing service that would also reduce the demand for biomass. In the comprehensive description of Smart Energy Systems given in [11], the coupling of energy and transport systems is addressed as a key issue to handle in the transition to a 100% renewable society. The study exemplifies the necessity of using a holistic perspective of all energy sectors to achieve an efficient fuel economy and a high level of integrated VRE. The Swedish electricity market region SE3 is of special interest due to the high demand for heat and electricity within the region and thus its dependency on neighboring regions for power supply. Also, the rapid increase of installed wind and solar capacity for power generation in this region is important. Transmission limitations to and from the region are of crucial importance and considered in this study.

TESs are currently used mainly for improved short-term heat production in DHSs [6], and in some cases for long-term storing of solar thermal [12]. There are, however, investigations of how TESSs in combination with CHP and/or P2H can improve production flexibility. In [10], for instance, it is shown that TESS in a system with a high share of VRE can increase the potential for P2H to consume surpluses by 24%. In [13], simulations show that TESSs in Finland can increase electricity generation in CHP by 15%. Furthermore, in [14], TESSs are shown to improve flexibility for both CHP and heat pumps, especially for systems with CHP production in back pressure steam turbines. Finally, in [15], a system with P2H and biomass-fired CHP is shown to benefit from either short-term or long-term TESSes depending on the access to biomass.

In all above-mentioned studies, VRE has been included as a parameter, but has not been studied in a way where the production strategies in the DHSs are adapted to primarily balance the VRE production. The studies show, in somewhat different ways, that TESSs can increase the potentials to consume surplus VRE and/or the CHP electricity generation. However, in [16], we demonstrated a novel production strategy where electricity production and consumption are prioritized over heat production, i.e., heat is a by-product of electricity production and/or consumption. In that study a small-scale DHS covering the heat demand in a single residential area was used as a case. The full potential of district heat production with CHP, heat pumps, and thermal storages on an aggregated level, primarily optimized to supply a balancing demand for electricity, and its impact on the demand for biomass, has on the other hand not yet been thoroughly investigated. This is the identified main research gap that is focused on in this study.

The overall contribution of this study is to enhance the understanding of how to accommodate a future energy system with high shares of VRE where both power surpluses and deficits must be considered. The major contribution is as an exemplifying case where the VPP concept on large scale is simulated to show the effects on fuel demand while providing power balancing production to reduce the VRE deficits and surpluses. A sensitivity analysis is performed to analyze how the mix of renewables affect the power balancing capacity and the biomass demand.

1.1. Purpose of the study and research questions

This study investigates potential power balancing capacity in a future Swedish power system with a high share of VRE production, by using DHSs with biomass-fueled CHP, large-scale pit TESs (PTES), and large-scale compression heat pumps. Simulations are made where the production in CHP and heat pumps are controlled by an estimated power balancing demand and the co-produced heat is stored if not directly supplied to district heating users. In the simulations, the aggregated heat demand in the electricity price area 3 (SE3) is used, where the heat demand is partially supplied by waste incineration and industrial waste heat utilization. A sub-purpose is also to analyze trade-offs between achieved power balancing capacity and demand for biomass. The research questions that the study aims to answer are:

1. To what extent can CHP and heat pumps supply the power balancing demand that is estimated for the SE3 region?
2. What capacity of PTES would be required for increasing production flexibility for CHP and heat pumps?
3. How will the balancing production in DHSs be affected by the shares of different VRE in power generation, and how does this in turn affect fuel use?

The paper is structured as follows. All calculations, simulation models, used data, and the scenarios are presented in the methods and materials section (section 2). The results are presented in section 3. The used methods and the results are thereafter discussed in section 4. Finally, the conclusions from the study are presented in Section 5.

2. Material and methods

This section presents and explains the calculations, simulation models, assumptions, and scenarios used in this study. In Fig. 1, a schematic representation is shown of the components that defines the simulated systems and how these connect. The black solid lines represent electricity flows and the dashed grey lines are the district heat flows. The power balancing demand \( P_{\text{bal}} \) in the figure is the control signal for the operation of the systems. The definition of \( P_{\text{bal}} \) is presented in section 2.2. The heat pumps to the left in Fig. 1 represents P2H-consumption of surplus electricity from the national grid. The waste and bio CHP units produce electricity to cover power deficits. The PTES-component between the CHP units and the heat pumps stores and supplies heat from/to the district heating grid. The heat only boiler (HOB) represents peak heat...
demand supply units. The industrial waste heat (IWH) component and the CHP\textsubscript{waste}-components represent baseload heat production units. The IWH component is also representing an industrial electricity demand. The residential buildings to the right represent the district heating demand and the household electricity demand.

2.1. Production strategies and scenarios

This section presents the reference case and the simulated scenarios. Also, the different operating strategies for the scenarios are described here. Table 1 compiles the capacities and properties for all system components and scenarios.

2.1.1. Reference case

The reference case is a “business as usual”-scenario. This means that the production in DHSs is primarily focused to supply the heat demand and that CHP electricity co-generation is merely a byproduct. This is a conventional operation strategy and will henceforth be referred to as the ‘heat strategy’. The reference case includes heat supplied from IWH, CHP\textsubscript{waste}, CHP\textsubscript{bio}, and HOBs. No heat pumps or storages are included in the reference case.

2.1.2. Scenarios 1 and 2

For scenarios 1 and 2, the DHSs are operated according to a production strategy where electricity is primarily produced in the CHP units to supply the power balancing demand, i.e., reduce the PRL. This strategy is referred to as the ‘electricity strategy’. Also, within scenarios 1 and 2, heat pumps are used to reduce NRL by using electricity for heat production. The heat co-produced in CHP or in heat pumps is primarily used to supply the heat demand. If the heat produced exceeds the demand it is stored in PTESs. No heat is wasted. A schematic presentation of the decision algorithm for the simulations is shown in Fig. 2. The average PRL in $P_{\text{bal}}$ is 5.7 GW (see Fig. 4) which is more than twice the installed capacity in the CHP\textsubscript{bio} (see Table 1). A threshold is used to focus the CHP operation on the higher levels of PRL. The threshold-value restricts the CHP from charging the PTES while producing electricity to supply low-level PRL. This is to increase availability to storage capacity for the higher levels of PRL. The threshold-value is iteratively lowered in the simulations for the co-produced heat in the CHP\textsubscript{bio} units to maximize the coverage of the heat demand. The HOBs are used to cover the heat demand not covered by the CHP\textsubscript{bio} and/or the PTESs. The higher the installed capacity in CHP plants, the greater the possibility of using stored co-produced heat between electric load peaks, which makes it possible to better direct the production to the occasions with the highest electricity demand.

For both scenarios 1 and 2, the heat pumps are assumed to have sufficient capacity to consume the largest NRL in the power balancing demand.

2.2. Power balancing demand

The power balancing demand, $P_{\text{bal}}$, is the difference between the power supply and demand mismatch, $P_{\text{diff}}$, with respect taken to

| Table 1 |
| Specification of parameters for the components simulated in the described system configurations, both reference case and scenarios. The folded-arrow symbol implies that the value in present column equals the value in the previous column. |

<table>
<thead>
<tr>
<th>Component</th>
<th>Parameter</th>
<th>Unit</th>
<th>Reference case</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal load</td>
<td>$Q_L$</td>
<td>GW\textsubscript{th}</td>
<td>11.9</td>
<td>11.9</td>
<td>11.9</td>
</tr>
<tr>
<td>IWH</td>
<td>$Q_{\text{IWH}}$</td>
<td>GWh\textsubscript{th}/h</td>
<td>0.49</td>
<td>0.49</td>
<td>0.49</td>
</tr>
<tr>
<td>CHP\textsubscript{waste}</td>
<td>$a$</td>
<td>–</td>
<td>0.3</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>CHP\textsubscript{bio}</td>
<td>$P_{\text{bio}}$^m$</td>
<td>GW\textsubscript{el}</td>
<td>1.49</td>
<td>1.49</td>
<td>1.49</td>
</tr>
<tr>
<td>HOB</td>
<td>$Q_{\text{HOB}}$</td>
<td>GW\textsubscript{th}</td>
<td>13.1</td>
<td>13.1</td>
<td>0</td>
</tr>
<tr>
<td>Heat pumps</td>
<td>$COP$</td>
<td>–</td>
<td>0</td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td>CHP\textsubscript{bio}</td>
<td>$P_{\text{bio}}$^m$</td>
<td>GW\textsubscript{el}</td>
<td>0</td>
<td>8.0</td>
<td>8.0</td>
</tr>
<tr>
<td>PTES</td>
<td>$V$</td>
<td>m\textsuperscript{3}</td>
<td>0</td>
<td>Iterated in simulation</td>
<td>16.7</td>
</tr>
</tbody>
</table>
and demand data for the non-Swedish regions, motivates this de-limitation. The total transmission capacity from SE3 to SE2 and SE4 is 12.4 GWel, while the cross-border transmission capacity from SE3 to neighboring countries (Denmark, Norway, and Finland) is merely 4.1 GWel [18]. With a high share of installed VRE in both Swedish and neighboring Nordic regions, this will impair the potential of cross-border transmission, if even available [35]. The power load \( P_L \), on regional level not supplied by the power supply, \( P_{VRE} \), is referred to as positive residual load (PRL). Similarly, if \( P_{VRE} \) exceeds \( P_L \), this is referred to as negative residual load (NRL). The shares of PRL and NRL that are possibly transferred to, or from, neighboring electricity market regions are limited by the transmission capacity limitations. Finally, \( P_{bal} \) is thus the PRL or NRL that is not exported to or imported from other market regions. In the simulations, \( P_{bal} \) is an hourly profile that is generated accordingly:

1. The difference, \( P_{diff} \), between the electricity load and VRE-production is determined separately according to (1) for all electricity market regions.

\[
P_{diff} = P_L - P_{VRE}
\]  

where \( P_L \) is the electricity load within the market region.

2. If \( P_{diff} < 0 \) for one specific region and one time-step, this region has an NRL. This NRL is transmitted to the other regions according to the pre-defined merit order, \( p = \{SE3, SE4, SE2, SE1\} \).

3. The possibility to transmit NRL to other market regions, is limited by transmission capacities, \( T_{cap} \), and/or if a PRL exist in other regions.

4. NRL that is not transmitted to other regions remains an NRL in the region.

5. Similarly, if \( P_{diff} > 0 \) there is a PRL in the region. This deficit is either covered completely or partially by NRL from other market regions. Deficits not covered remain a PRL for the region.

6. A time-series with the remaining NRL and PRL for each region constitutes the \( P_{bal} \)-profile.

Fig. 3 shows the Swedish electricity market regions and the geographic location of these. The diagram to the right illustrates the definition of the \( P_{bal} \)-demand. The figure shows a case where the transmission capacities to the neighboring regions are the limiting factor, and not the lack of power deficits in other regions. \( T_{cap,i} \) is the transmission limitations for regional import of power and \( T_{cap,e} \) is the limitation for export.

Hourly data for wind and solar power generation and electricity use for each market region in Sweden and for the year 2018 [17] is used to generate the power balancing profile. Annual values for this data are given in Table 2 and the hourly data profiles are presented in Appendix A.

The VRE production from wind and solar power is calculated according to

\[
P_{VRE} = C_1 P_W + C_2 P_{PV},
\]

where \( P_W \) and \( P_{PV} \) are the hourly wind and PV electricity production in 2018. \( C_1 \) and \( C_2 \) are scaling factors that on an aggregated national level scale the wind and solar production to represent 60% and 10% of the annual Swedish demand, respectively. \( C_1 \) and \( C_2 \) are defined as

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**Fig. 2.** Schematic presentation of the algorithm’s decision priorities.

**Fig. 3.** The electricity market regions in Sweden isolated from the other market regions in the Nord pool electricity market (left). An illustration of the definition of \( P_{bal} \) for one region and the case where the transmission capacities are limiting (right).

In Fig. 4, the hourly $P_{\text{bal}}$-profile for the SE3-region is shown, both as a consecutive time-series and as a duration curve. The demand is calculated according to the previously described procedure. The result is an intermediate net profile with remaining PRL, some sections of perfect balance between demand and production (almost 1,700 h), but also 700 h of excess electricity production resulting in an NRL.

The peak PRL is 14.6 GWel and occurred during end of February. For comparison: the total installed hydro power capacity in Sweden is 16.3 GWel with an expected availability of 82.2% giving approximately 13.4 GWel at any hour [18]. The peak NRL was 8 GWel in end of June. Annual PRL was 36.2 TWhel and annual NRL was 0.9 TWhel.

### 2.3. Heat load, production capacities, and biomass demand

The heat load profile in the simulations is approximated from hourly outdoor temperatures and an annual heat demand according to a method described in Ref. [19]. Outdoor temperature data from a representative city in the SE3-region (Västerås), is used. The generated hourly heat load profile is scaled to represent the annual district heat demand of 39.2 TWhth within SE3. IWH supplied 4.27 TWhth and waste incineration supplied another 10.38 TWhth to the SE3-DHSs during 2017 [20]. The IWH is assumed to be supplied at a constant output over the year (see Table 1). Waste incineration plants (CHPwaste) are operated more or less continuously, with revision periods assumed during summer. The CHPwaste plants are assumed to be configured for bypassing of turbines. Thus, they will be operated in heat-only mode if there is no electricity demand. The default is, however, that these plants perform cogeneration with a power generation capacity of 447.9 MWel.

The installed heat supply capacity in SE3 was estimated to be 17.6 GWth based on data from Ref. [21]. There is 2.2 GWth installed in CHP units within SE3 [18]. With a typical power-to-heat ratio (x-value) for solid fuel CHP units of 0.5, this correspond to 4.5 GWth [22]. Hence, 13.1 GWth capacity is assumed to be in heat only-boilers (HOB).

### Table 2

Data used for deriving the $P_{\text{bal}}$-profile for SE3.

<table>
<thead>
<tr>
<th>Component</th>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric load, SE3, 2018</td>
<td>$P_L$</td>
<td>16.7</td>
<td>GWel</td>
</tr>
<tr>
<td>Wind power, SE3, 2018</td>
<td>$P_W$</td>
<td>84.5</td>
<td>TWhth</td>
</tr>
<tr>
<td>Scale factor, wind</td>
<td>$C_1$</td>
<td>4.8</td>
<td></td>
</tr>
<tr>
<td>Wind power, SE3, this study</td>
<td>$C_1P_W$</td>
<td>10.4</td>
<td>GWel</td>
</tr>
<tr>
<td>Solar power, SE3, 2018</td>
<td>$P_{PV}$</td>
<td>0.1</td>
<td>GWel</td>
</tr>
<tr>
<td>Scale factor, PV</td>
<td>$C_2$</td>
<td>90.7</td>
<td></td>
</tr>
<tr>
<td>Solar power, SE3, this study</td>
<td>$C_2P_{PV}$</td>
<td>8.9</td>
<td>GWel</td>
</tr>
<tr>
<td>Regional electricity balance (no transmission), $P_{\text{diff}}$, SE3</td>
<td>PRL</td>
<td>14.6</td>
<td>GWel</td>
</tr>
<tr>
<td>NRL</td>
<td>8.0</td>
<td>TWhth</td>
<td></td>
</tr>
<tr>
<td>Balancing demand, $P_{\text{bal}}$, SE3</td>
<td>PRL</td>
<td>14.6</td>
<td>GWel</td>
</tr>
<tr>
<td>NRL</td>
<td>8.0</td>
<td>TWhth</td>
<td></td>
</tr>
</tbody>
</table>

\[
C_1 = 0.6 \frac{\sum P_L}{\sum P_W}
\]

and

\[
C_2 = 0.1 \frac{\sum P_L}{\sum P_{PV}}
\]
For the reference case, the heat demand limits the availability of the CHP power capacity by 23.5%, according to the Swedish national transmission system operator, Svenska Kraftnät [18]. The CHP power generation capacity is therefore 0.765 × 2,257 = 1,727 MWth in the reference case. This is fairly close to the maximum power production registered from CHP plants in SE3-region in 2018, that was 1,399 MWel [23]. All units in the reference case are assumed to primarily follow the heat demand.

For scenario 1, the currently installed CHP electric power of 2.2 GWel is used, but assumed to be fully dispatchable at all times to primarily supply the electricity balance demand, \( P_{bal} \).

Scenario 2 assumes that all the heat supply capacity is in CHP plants. The power generation capacity in such a case would be 8.8 GWel, assuming an \( \alpha \)-value of 0.5. The units are operated to primarily supply the power balancing demand.

All data describing the system and the scenarios are presented in Table 1 and in Table 2 is the electricity balancing demand. The heat pumps extract heat from ground source and/or sewage water from waste water treatment plant, and are thus presented. The heat pumps extract heat from ground source and/or sewage water from waste water treatment plant, and are thus presented. This is fairly close to the maximum power production registered from CHP plants in SE3-region in 2018, that was 1,399 MWel [23]. All units in the reference case are assumed to primarily follow the heat demand.

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All data describing the system and the scenarios are presented in Table 1 and in Table 2 is the electricity balancing demand. The heat pumps extract heat from ground source and/or sewage water from waste water treatment plant, and are thus assumed to have a constant coefficient of performance (COP) of 3. The biomass CHP plants (CHPbio) is represented as an average plant based on a variety of different burners and biomass fuel types. An \( \alpha \)-value of 0.5 is used for these plants. They also are assumed to be able to operate down to a minimum load of 15% of the nominal power and with a ramping rate of 4% of the nominal power, per minute. The characteristics of the PTESs are described in section 2.4.

Fig. 5 shows the heat demand together with the assumed baseload production from IWH and CHPwaste. The peak heat demand is 11.9 GWth and total demand was 39.2 TWhth for the SE3-region.

An average heating value for wood of 2.88 GJ/m³ or 16.92 GJ/ton is the produced heat and \( Q_{fuel} \) is described as

\[
Q_{fuel} = \sum Q_{ch(i)} + \sum Q_{el(i)} \eta_{tot}.
\]

(5)

\( Q_{th} \) is the produced heat and \( Q_{el} \) is the produced electricity and \( \eta_{tot} \) is the CHPs or HOBs total efficiency for converting energy in the fuel to electricity and/or useful heat.

2.4. Pit thermal energy storage

Pit thermal energy storages (PTESs) are included in the simulations to decrease the limiting impact of heat load variations on the heat production in heat pumps and CHP plants. All DHSs in SE3 are assumed to have PTESs in the shape of truncated rectangular pyramid ponds, dug into the ground, with an insulated top (see Fig. 6A). The top is at ground level (see Fig. 6B). The PTES modeled here is inspired by a PTES built and operated in Dronninglund, Denmark [25]. Data describing the conditions for, and characteristics of, the PTES as implemented in the model are presented in Table 3.

The heat loss from the storage is calculated from Fourier’s law on heat conduction

\[
Q_{loss} = q_{top} + q_{wall} + q_{bottom} = \frac{A_{top} \lambda_l (T_{top} - T_a)}{d_t} + \frac{A_{wall} \lambda_g (T_{wall} - T_u)}{\alpha_x} + \frac{A_{bottom} \lambda_g (T_{bottom} - T_u)}{\alpha_x}
\]

(6)

\( A_{top}, A_{wall}, A_{bottom} \) are the areas of the storage top, walls and bottom. \( \lambda_l \) is the thermal conductivity for the top lid, \( \lambda_g \) is thermal conductivity for the ground. \( T_{top}, T_{wall}, T_{bottom} \) and \( T_u \) are average temperatures at the storage top, walls, and bottom, respectively. \( T_a \) is the ambient temperature in the outdoor air, and \( T_u \) is the temperature in the ground. \( d_t \) is the thickness of the top insulation and \( \alpha_x \) is the thermal conductivity for the ground.

The heat supplied to the storage (\( Q_{PTES} \)) is calculated as

\[
Q_{PTES}(i) = Q_{PTES}(i-1) + Q_{PTES\uparrow} - Q_{PTES\downarrow} - Q_{loss}(i).
\]

(7)

The heat supplied to the storage (\( Q_{PTES\uparrow} \)) is described as

\[
Q_{PTES\uparrow}(i) = Q_{CHP}(i) + Q_{heat\,pumps\,(i)} - Q_{L}(i) \quad \text{iff} \quad Q_{L}(i) < Q_{CHP}(i)
\]

\[
+ Q_{heat\,pumps\,(i)},
\]

and the heat from the storage to supply the heat demand (\( Q_{PTES\downarrow} \)) is

\[
Q_{PTES\downarrow}(i) = Q_{heat\,demand\,(i)} + Q_{CHP\,waste\,(i)} - Q_{L}(i) \quad \text{iff} \quad Q_{L}(i) < Q_{CHP\,waste}(i)
\]

\[
+ Q_{heat\,pumps\,(i)},
\]

Fig. 5. Figure A shows the time series of the modeled heat load in SE3 and figure B shows the duration of the heat load and baseload production.

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Energy efficiency is basically the quota between the total annual amount of heat supplied to the PTES ($\sum_i Q_{TES}$) and the amount of heat supplied to the PTES ($\sum_i Q_{TES}^i$). The efficiency is defined as

$$\eta_e = 100 \cdot \frac{\sum_i Q_{TES}^i}{\sum_i Q_{TES}}$$

(9)

The degree of utilization, $\eta_u$, indicates how extensively the storage capacity is used and is defined as the quota between the total annual amount of heat supplied from the PTES, and the nominal capacity of the storage ($Q_{max}$). $\eta_u = 1$ means that the storage has been used in an extent that corresponds to one full storing cycle for the simulation period. It is defined as

$$\eta_u = \frac{\sum_i Q_{TES}^i}{Q_{max}}$$

(10)

The storage capacity is defined as

$$Q_{max} = c_v \Delta T V$$

(12)

where $c_v$ [J/(m$^3$K)] is the volumetric heat capacity of water, $\Delta T$ is the temperature difference in the PTES.

### 3. Results

In this section, the results are presented in response to the research questions. First the power balancing production is presented in section 3.1 and thereafter the required storage capacity in section 3.2 and finally the result of the VRE mix analysis is presented in section 3.3.

#### 3.1. Power balancing production

In Table 4, the peak and annual values for the PRL and NRL in $P_{bal}$ are shown. It can be seen that the NRL in the reference case is not affected at all since no heat pumps are included in this case. For both scenario 1 and 2, however, all NRL is consumed via heat pumps. The peak PRL is reduced by 12% for the reference case. For scenario 1, the peak PRL is reduced by 15%, while for scenario 2 the peak PRL is reduced by 52%. The latter is because of the significantly higher capacity in CHP units in scenario 2.

For the reference case, 20% of annual PRL is reduced. For both scenarios 1 and 2, however, about one third of the annual PRL is reduced despite the significant difference between the scenarios in reduced peak PRL. Thus, even though scenario 2 have about four times the CHP power generation capacity as the reference case and scenario 1, the larger capacity is mainly reducing the PRL peaks and is therefore relatively less utilized.

Fig. 7 shows how the power production in scenario 2 is significantly different from both scenario 1 and the reference case. For the latter two, it is clear that the CHP power production is limited by the production capacity (1.71 GW$el$ for reference case and 2.26 GW$el$ for scenario 1) rather than the level of $P_{bal}$. The right column of diagrams in Fig. 7 show correlation between $P_{bal}$ and the power production in CHP and power consumption in heat pumps. For scenario 1, the CHP units are operated constantly at the maximum capacity level, while for the reference case (top right diagram), the output varies significantly. For scenario 2 (bottom right diagram), the CHP units are operated to cover the PRL peaks above 4.98 GW$el$. This is possible because of the installed capacity of 8.81 GW$el$. This level is iteratively derived according to the description in section 2.1. The biomass CHP units in scenario 2 are only operated for about 2,300 h in total. In scenario 1 the corresponding number of hours is 5,600 and in the reference case it is 5,800 h. In all the simulated scenarios the waste incineration CHP plants bypass the turbine and operate in heat-only mode for about 2,400 h and co-produce power for 6,300 h. For 4,000 h, waste incineration CHP constitutes all thermal power generation for scenario 2.

In Table 5, key figures for the heat production are shown for the reference case and the two scenarios. For the reference case, all produced heat is directly supplied to the DH network. This is because neither heat pumps nor PTEs are included in the system configuration for this case. The largest suppliers of heat for the reference case are the biomass fueled CHP units, covering about 50% of the heat load.

For scenarios 1 and 2, both heat pumps and PTEs are included. This does not, for any of the scenarios, affect heat supplied from IWH and waste incineration when compared to the reference case. For scenario 1, slightly less heat is produced in HOBs compared to
the reference case and the biomass fueled CHP units are the main heat producers. The use of biomass for CHP production is 11% higher in scenario 1 compared to the reference case. The increased fuel use is because more electricity is co-generated in scenario 1, than for the reference case where CHP units occasionally are used for heat-only production (compare with Table 4). About 25% of this heat is stored in PTEs. Heat is also produced in heat pumps in scenario 1 and of that, approximately 75% is stored.

For scenario 2, HOB capacity is replaced by biomass fueled CHP capacity and thus the production in CHP is increased by about 23% compared to the reference case. Total fuel use is increased by about 12%. The lesser increase in fuel use compared to CHP production is due to the lack of HOB production. The CHP units in scenario 2 produce nearly 60% of the total heat supply, but only half of this is directly supplied to the DH network, the rest is stored in PTEs. The supply of heat to the DH network is almost equally divided between waste incineration plants, PTEs and biomass CHP. The heat produced in heat pumps is similar in scenarios 1 and 2.

In Fig. 8, duration diagrams for the heat supplying technologies in the reference case and the two scenarios are shown. The heat supply from IWH and waste incineration is similar in the reference case and the two scenarios. The PTEs is used to a larger extent in scenario 2 compared to scenario 1. The heat supplied to DH network from the biomass CHP ($Q_{CHP}$) in the reference case is limited by the heat demand ($Q_I$). In the scenarios 1 and 2 it is clear that the CHP production is less limited by the heat demand due to the possibility to store heat in the PTEs. The lower CHP capacity in scenario 1 compared to scenario 2 explains the significantly lower grey peaks for scenario 1. Finally, the figures show that the heat pumps produce heat at a capacity of 24 GWth which is significantly larger than the average and peak heat demand levels. The heat pumps are also generally operated during low heat demand hours, i.e., summer months.

### 3.2. Storage capacity

Fig. 9 shows energy transactions and energy content in the storage. Table 6 gives key figures for how the storage is used in the two scenarios.

The PTEs in Scenario 1 functions as a combined long- and short-term storage (see Fig. 9 and Table 6). 74.9 million m³ of storage volume is required, which corresponds to a storage capacity of 4.35 TWhth (18% of $Q_I$). The storage heat losses in scenario 1 are 2.29 TWhth (33%) and the energy efficiency of the storage use is 67%. The degree of utilization is 1.06 which implies that the energy transactions to and from the storage correspond to 1 total storage cycle of the capacity. The overall use of the storage follows a seasonal pattern where most heat is supplied to the PTEs in one part of the year and extracted from the storage in another part of the year. This, in turn, yields long retention times for the stored heat and increases heat losses.

For scenario 2, the PTEs are used more extensively when compared to scenario 1. In Fig. 9 (right side diagrams) the results show that the storage utilization is more irregularly distributed over the year and differ from the seasonal pattern seen for scenario 1. This is because of the higher capacity in CHP that yields large amounts of stored co-produced heat in the PTEs. The stored heat is used when the heat output from CHP units is insufficient to supply the heat demand due to a low power balancing demand. In scenario 2, a storage volume of 72.8 million m³ is required due to the increased capacity in CHP. This corresponds to a PTEs capacity of 4.23 TWhth, which is 17.2% of $Q_I$. The storage heat losses are 2.23 TWhth, i.e., 16% of the heat supplied to the storage. The storage efficiency is 81% and the degree of utilization is 2.6, both higher than for scenario 1. The higher degree of utilization confirms that the storage is less of a seasonal storage compared to scenario 1.

### 3.3. Analysis of VRE-mix

An analysis is performed to investigate how the results are affected by different shares of electricity produced from wind and solar in the VRE profile. Three parameters are focused on, peak PRL, annual PRL, and fuel use, since these are identified as crucial for the results and for the research questions. For baseline, the VRE shares 10% PV and 60% wind is used. Table 7 shows the shares of wind and solar used for the analysis. Note that the scaling of wind and solar power is relative the annual national demand and not relative the demand in SE3 only.

Three main findings from the analysis are seen in Fig. 10. First, varying the shares of VRE does not affect the achieved reduction of peak PRL for scenario 1 (solid blue line) and only slightly for scenario 2 (solid red line). Secondly, the annual electricity production (dashed lines) increases for both scenarios with a VRE production mix containing a larger share of wind power compared to the baseline VRE mix. This is explained by the fact that a high share of PV produces a lot of NRU, which in heat pumps produces heat which in turn compete with heat co-produced in CHP units.

Finally, the analysis shows that the VRE shares have significant impact on fuel use. For both scenarios 1 and 2, the mix of 70% wind and 10% PV yields higher biomass use by 1% and 4%, respectively, when compared to the reference case. The corresponding change in fuel use for the baseline VRE-mix is 11% and 12%, as presented in Sections 3.2 and 3.3. Thus, a higher share of wind leads to less increase in the demand for biomass. 65% wind and 15% PV (the mid-case in Fig. 10) yields reduced demand for biomass for both scenarios when compared to the reference case. This means that providing power balancing services can potentially be combined with a decreased fuel use, compared to when the system is conventionally operated, i.e., according to a heat strategy as in the reference case.

20% PV and 60% wind power (the left case in Fig. 10), on the
other hand, reduces fuel demand significantly for scenarios 1 and 2 compared to the reference case. The large impact of the share of PV on reducing the fuel demand is explained by PV generation being concentrated to a few hours of the day and mainly during summer months when the power demand is generally low. Therefore, most PV generated electricity becomes NRL that is consumed in heat pumps to produce heat that is to a vast extent stored in the PTESs. This heat is at a later stage used to replace heat from the CHP units. Which, in turn, limits the possibility to provide power balancing production from CHP units. Thus, the use of fuel is significantly reduced with this VRE mix, but it is at the expense of potential balancing power production in CHP units.

4. Discussion

This study investigates the use of DHS for power balancing production in the Swedish electricity price region SE3 for a future scenario with a high share of VRE. The potentials for both positive and negative balancing services are evaluated. The study also examines how the demand for biomass from power balancing production in CHP units are affected by the ratio of wind and solar power in the VRE mix.

The results for scenarios 1 and 2 show a similar annual reduction in PRL, but a significant difference between the two scenarios in peak PRL supply. The results show that TESs significantly can increase the
amount of electricity produced. However, it is also clear that, when CHP units are operated according to the electricity strategy, as in scenarios 1 and 2, the balancing power supply depends mainly on the CHP production capacity rather than the access to TESs. The higher CHP capacities in scenario 2 have a significant impact on reducing the peak PRL. A consequence of this is that the CHP units are inactive for a significant part of the year in scenario 2, which might also affect the feasibility for investments in CHP.

The following reflection is made to put the results into context. The highest PRL peak in the simulations is in late February (Fig. 4). The coinciding demand for electricity in Sweden, on that occasion, is 8 GWel. The available hydropower capacity in Sweden is about 13.4 GWel [18], and another 1.5 GWel in condensing power production units. Thus, this indicates that power import and sufficient transmission capacities are probably necessary to cover possible future VRE deficits. Hence, increasing the flexibility, controllability, and capacity in CHP power generation, as investigated here, is of importance. The results show that shifting the production strategy is not sufficient to cover the PRL of a future potential electricity balancing demand. Increasing CHP capacity is also required.

It should be noted that there is a discrepancy between the simulated production in the reference case in this study and reported production data for SE3 in 2017. About 63% of the simulated production (4,691 GWhel) was reported according to SVK [23]. This is explained by the fact that in 2017 about 40% of the electricity demand was supplied by nuclear power, which thus reduced the need for CHP-produced electricity. Furthermore, DHSs have individual constraints regarding production planning, staffing, revision periods, technical constraints in ramping, and power-to-heat ratio not covered in this study, which can explain the difference. This emphasizes that CHP units’ power capacities are not fully utilized.

The second research question considered the required storage size for supporting the electricity strategy applied in scenarios 1 and 2. The volume of the reference PTES in Dronninglund is 60 000 m³. Based on this size, the results indicate that the amount of required PTESs in the SE3-region would be 1,248 and 1,193 for scenarios 1 and 2, respectively. There are somewhere around 250 DHSs in SE3 [20] with an installed storage capacity for diurnal use of 0.2 TWhth [36], this would imply on average 4–5 PTESs per system. This, however, is an estimate and a more correct determination of storage size should relate to power capacity installed. PTES can be constructed quite easily and at low relative costs. The storage can also be integrated with larger buildings/constructions to minimize land-use conflicts. Such implementations would improve the efficiency, but also increase the construction cost significantly compared to a PTES with a non-trafficable lid, as described in Ref. [27]. It should be noted that larger storage sizes could yield higher storage efficiencies, due to less relative heat losses. For storage sizes above 100 000 m³, and where the geology could yield higher storage efficiencies, but also increase the construction cost significantly compared to a PTES in a non-trafficable lid, as described in Ref. [27]. It should be noted that larger storage sizes could yield higher storage efficiencies, due to less relative heat losses. For storage sizes above 100 000 m³, and where the geology permits, rock cavern TES can be suitable. A 1 million m³ rock cavern TES is for example currently being constructed in Vantaa, Finland [28]. However, TESs of that size is not valid for all DHSs.

A sensitivity test was performed to assess the calculation of storage heat losses. The PTES model in this study uses mean

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Table 5

Heat production from different units and the supply to DH for reference case and the two different scenarios. Percentage refer to share of total production or share of heat supplied to DH. Last in table is the fuel use shown.

<table>
<thead>
<tr>
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<th>Reference case</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>∑Qprod To DH</td>
<td>∑Qprod To DH</td>
<td>∑Qprod To DH</td>
</tr>
<tr>
<td>QVHO</td>
<td>4.27 TWhth</td>
<td>4.27 TWhth</td>
<td>4.27 TWhth</td>
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<td>10.38 TWhth</td>
<td>10.38 TWhth</td>
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<td>4.71 TWhth</td>
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<td>19.82 TWhth</td>
<td>19.82 TWhth</td>
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<td>Qheat pumps</td>
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<td>2.76 TWhth</td>
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<tr>
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<tr>
<td>QIWH</td>
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<tr>
<td>Qi</td>
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<td>39.18 TWhth</td>
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<td>mfuel (Mton)</td>
<td>8.14</td>
<td>9.00</td>
<td>9.15</td>
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Fig. 8. Duration of supplied heat in all three cases. In the reference case no PTES or heat pumps are used. In Scenario 1 all different production units are present. In Scenario 2 the HOB has been fully replaced by PTES.
temperatures for the surface areas instead of, for example, a model of a stratified water tank that would capture how the losses vary with the amount of stored heat. In the sensitivity test, the extreme temperatures of the surface walls are studied to define the potential variations of the storage heat losses. Thus, a maximum temperature is applied for the entire surface area to represent a fully charged storage, and a minimum temperature is applied to represent an uncharged storage. The analysis shows that for scenario 1, the relative losses from the PTESs vary between 40% and 28% depending on the amount of heat stored. The average losses presented in the previous section for the same scenario is 33%. The corresponding figures for scenario 2 are that the relative losses vary between 21% and 13%, and in the results for scenario 2 the average losses are 16%. This shows that the average temperature model used here performs sufficiently well when complete storage cycles are studied.

The third research question is focused partly on how the balancing production is affected by the VRE mix, and partly on how this influences fuel use. Previous studies have pointed to the differences in access to biomass in different parts of the world [29] and the danger of overexploitation of biomass (deforestation, biodiversity, land-use change) [30]. Also, competition for the use of biomass has been pointed out [31]. Increased CHP power generation means increased fuel use. 11% and 12% higher demand for biomass as fuel was shown for scenarios 1 and 2, respectively, when compared to the reference case.

The analysis of the VRE-mix (Fig. 10) shows that this has a significant impact on the results. It can thus be noted that there is to
some extent a conflict between power balancing production in CHP units and moderate demand for biomass. With an increasing share of PV, the fuel use is reduced, but so is also the potential for positive power balancing production. This is caused by competing heat production in heat pumps from NRL that limits the production in CHP units. Changing the VRE-mix from 10% to 15% PV indicates relatively small changes in the power balancing capacity, but the fuel use shows a significant reduction. Continuing up to 20% PV, however, shows that the potential for power balancing becomes very small compared to the reference case. The demand for biomass is on the other hand continuously reduced, but then requiring very large capacities in heat pumps. Hence, a trade-off threshold seems to be around 15% PV and 65% wind power. This can be related to a report from the Swedish power system operator (Svenska kraftnät) on future infrastructural challenges [37]. Svenska kraftnät expects an expansion of wind power, on national level, to approximately 45% (67 TWh) and solar power to 5% (7 TWh) of the annual Swedish electricity consumption in the year 2040. In 2020, the annual electricity demand in Sweden was supplied to 0.3% by solar power and to 21% by wind power [23]. Thus, the results presented here suggest that higher shares of PV in the VRE mix than currently and expectedly different. This aspect will likely be crucial for the possibility to invest in DHSs’ contribution to power system balancing, and should be object for further studies of heat and power market solutions that would support this kind of system configuration.

5. Conclusions

This study shows that CHP and P2H production in DHSs located within the Swedish electricity market region SE3, and in combination with PTESS, potentially can contribute with power balancing services in a future scenario with high shares of VRE production. The results, however, show that this power balancing contribution can be further increased by a number of considerations. For instance, potential reduction of positive and/or negative residual peak loads are directly related to the installed capacity in the CHP and/or heat pump units. Thus, high peaks require high capacities that may impair the economic feasibility of the plants, this due to few peak hours and therefore low utilization factors for the units. On the other hand, even with capacities significantly lower than peak load, significant reduction of annual loads can be achieved. Further, the economic feasibility of the CHP production will be challenged by the less operation hours with this strategy when compared to conventional CHP production. Therefore, if CHP is to be used for power balancing, the utilities need to be compensated economically for this, i.e., enough to consume the highest NRL peak. Based on information in Ref. [33], large-scale sea-water heat pumps is expected to have a nominal investment cost of 0.38 M€/MWth in 2050. The corresponding cost for a ground source heat pump is according to Pieper et al. 0.73 M€/MWth [34]. However, the capacity required for consuming all NRL means that the heat pumps are significantly over-dimensioned when considering the heat demand levels. This means that most of the capacity will not be utilized for most hours of the year. Therefore, dimensioning the capacity of the heat pumps to cover a part of the NRL should be considered. A heat pump capacity that consumes 50% of the highest NRL peak would still consume 95% of the annual NRL. This would also reduce the required size of the PTESSs somewhat, but of course require the non-consumed NRL-peaks to be used some other way, or curtailed.

Furthermore, the operation-times for the heat pumps in the simulated scenarios are about 1,000 h. Heat pumps that are used as part of conventional base-load production generally operate about 4,000–5,000 h. For DHS operators to invest in heat pumps and use them according to the strategy put forth in this study, would therefore most likely require a different pricing model, one that considers the provided balancing services by the heat pumps. An alternative is to use electric boilers for P2H instead of heat pumps, since it is a significantly cheaper technology [33]. Also, with a heat-to-power ratio of approximately 1 for electric boilers compared to 3 for the heat pumps, more electricity is consumed per unit heat produced. Furthermore, since the heat demand has been shown to be a limiting factor for P2H electricity consumption, electric boilers could be considered favorable for some systems also from this aspect.

The cost for retrofitting HOB to CHP units is difficult to assess due to varying conditions in different heat production systems. Thenominal investment cost for new CHP units is, however, according to the Danish Energy Agency [33], generally 6–9 times higher than for HOBs. The cost depends on a number of factors such as capacity, choice of turbine technology, and type of fuel. Based on the same report, the cost-difference for investments in HOBs compared to CHP with a typical thermal output of 132 MWth is about 139 M€. For a conventional CHP investment, the income from sold electricity is an important aspect. When operated according to the electricity strategy, as in scenarios 1 and 2, and in a system with large shares of VRE, CHP electricity production and revenues is expectedly different. This aspect will likely be crucial for the possibility to invest in DHSs’ contribution to power system balancing, and should be object for further studies of heat and power market solutions that would support this kind of system configuration.
novel business models will probably be necessary. Also, heat pumps and CHP units will compete for the same heat loads in the DHSs. This means for example that produced heat from heat pumps consuming NRL may limit future possibilities for CHP units to cover PRL. Thus, the balance between the needs for covering PRL and consuming NRL must to be considered.

The required PTES capacity for achieving sufficient production flexibility in CHP and heat pumps is around 4 TWhth for the DHSs in the SE3-region, which corresponds to 17–18% of these DHSs aggregated heat load. The installed storage capacity in SE3 is currently about 0.2 TWhth which means that large investments in storage capacity will be required to reach the required flexibility.

Finally, it can be concluded that to avoid an excessive increase in fuel demand while providing power balancing services with CHP and heat pumps, the mix of VRE power generation is crucial. Solar power in the VRE mix reduces the demand for biomass more than wind power do. However, too large shares of solar power (above 15% of the power demand) yield high NRL peaks that, if consumed in heat pumps, limit the production in CHP units. A VRE mix consisting of 15% PV and 65% wind power, relative to the annual electricity demand, yields a good balance in reducing biomass demand without limiting the PRL supply. This indicates that, in this aspect, larger shares of PV in the system than what is expected by the Swedish power system operator could be favorable.

Declaration of competing interest

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

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Appendix A. Graphical abstract credentials

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Appendix A