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Economic analysis of using excess renewable electricity to displace heating fuels

Alessandro Pensini [a,*], Claus N. Rasmussen [a], Willett Kempton [a,b,c]

[a] Center for Electric Power and Energy, DTU Elektro, Danmarks Tekniske Universitet, 2800 Kgs. Lyngby, Denmark
[b] Center for Carbon-Free Power Integration and College of Earth Ocean and Environment, University of Delaware, Newark, DE 19716, USA
[c] Department of Electrical and Computer Engineering, University of Delaware, Newark, DE 19716, USA

HIGHLIGHTS

- Excess electricity from 100% renewable scenario can replace most of heating fuels.
- Heat production cost is comparable or lower than heating with fossil fuels.
- Heat pumps based district heating is less expensive than resistive heating.
- Fossil fuels are used only as backup and consumption can be reduced by almost 100%.
- Energy storage can inexpensively reduce gas consumption and CO_2 emissions.

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ABSTRACT

Recent work has shown that for high-penetration renewable electricity systems, it is less expensive to install higher capacity of renewables and to allow generation to exceed load during some hours, rather than to build so much storage that all electricity can be used to meet electrical load. Because excess electricity appears to be cost-optimum, this raises the question as to whether the excess electricity, which in the case of wind power is predominately produced in colder weather, might displace other fuels for purposes such as heat. This study models using excess electricity for heating, based on an analysis of electricity and heat use in a TSO in the North-Eastern part of the United States (PJM Interconnection). The heating system was modeled as heat pump based district heating (HPDH) with thermal energy storage (TES). Thus, excess electricity is transformed into heat, which is easy and cheap to store near the point of use. As an alternative to HPDH, the use of distributed electrical resistive heating coupled with high temperature thermal storage (HTS) was also assessed. In both cases, a natural gas fired boiler (NGB) was modeled to be installed in the building for back-up heat. An algorithm that calculates the total cost of a unit of heat was used to determine the economically optimal size of the system's main components and the influence that natural gas (NG) and electricity prices have on this optimum. It was found that a system based on heat pumps (HP) and centralized thermal storage supplies building heat at a lower or similar cost than conventional systems. In most cases electric resistive heating with HTS was found to be less cost-effective than HPDH. The consumption of natural gas can be reduced to as little as 3% of that used by an entirely NG-based heater. Also, thermal energy storage was found to be crucial when it comes to reducing the need for fossil fuels for heating (in this model, as backup heat).

1. Background

The theoretical potential of renewable resources (RES) on earth is consistently higher than the energy requirement for human related activities (the solar radiation alone on the earth's surface is more than three orders of magnitude larger than the global energy demand [1]). However, these resources, which are also non-carbon based, are not available in the required form and have to be converted–the expense of conversion and integration with existing power systems thus sets the parameters of today's economic completion between RES and transitional fuels. A comprehensive approach to meet the global energy requirements for all purposes (electric power, transportation, heating/

* Corresponding author. Address: Center for Electric Power and Energy, DTU Elektro, Danmarks Tekniske Universitet, 2800 Kgs. Lyngby, 325 Elektrovej, Denmark. Tel.: +45 45253483; fax: +45 4588 6111.

E-mail address: alessandropensini@gmail.com (A. Pensini).

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Nomenclature

$€_{el}$	cost of electricity
$€_{MW\ h,th}$	average cost of a unit of heat supplied
$€_{NG}$	cost of natural gas
$€_{year}$	yearly production cost of a unit of heat
NG4, NG8, NG16	scenarios based on different price of natural gas (one, two, and four times the current price)
EL0, EL5, EL10	scenarios based on different price of excess electricity (free of charge, 5 $kW h^{-1}, and 10 $kW h^{-1})
COP	coefficient of performance
DH	degree hours
DHW	domestic hot water
E	energy content of the thermal storage
E_{max}	total size of the thermal storage units
HP	heat pump / scenarios with HP technology
HPDH	heat pump based district heating
HTS	high temperature thermal storage
i	index for each single state entirely or partly belonging to PJM
I	investment cost
k	index for the four cost centers (heat pumps, thermal storage, distribution network and natural gas fired boilers)
LHV	lower heating value
m	index representing the months from January 1999 and December 2002
NG	natural gas
NGB	household natural gas fired boiler
OM	yearly operations and maintenance cost
P_{ex}	excess electricity
PJM	is an electricity supply area in the North-Eastern United States
P_{max}	total size of the heat pump fleet
Q_{BP}	heat bypassing the thermal storage that goes directly to the end user
Q_{in}	heat from the heat pump
Q_{load}	aggregated thermal load
Q_{month}	monthly heating demand
$Q_{NG,month}$	monthly natural gas consumption
$Q_{s,i}$	heat into the thermal storage
r	interest rate
R	resistive heating unit, in scenarios with resistive heating technology
RREEOM	regional renewable electricity economic optimization model [7]
SH	space heating
t	index representing the hours from January 1999 and December 2002
TES	thermal energy storage
z	lifetime of the individual component
α	proportionality factor between the degree-hour values and the space heating requirement
γ	ratio between the population of a state that is served by PJM and the total state population
η_d	efficiency of the district heating distribution network
η_s	loss rate of the thermal storage
φ	share of natural gas in space heating and domestic hot water
ψ	percentage of natural gas used for space heating and domestic hot water

cooling, etc.) by means of renewable resources is proposed in [2,3], which proposes a future scenario in 2050 with a mix of RES providing all energy needs at costs similar to today's. Scenarios like this with very high penetration of renewables (equal or close to 100%) for the electricity sector have been studied in recent years by several authors [4–7]. In [8], the authors study a total renewable electricity scenario based on a combination of RES and pumped hydro as storage. The outcomes of the research is that the total electricity consumption worldwide can be met exploiting only green energy. Recently, Budischak et al. found that a mix of different and geographically distributed renewable sources coupled with transmission and energy storage could provide almost all the electrical requirements in a large interconnection [7].

When analyzing the integration of renewable electricity, the time mismatch between fluctuating production and demand has to be considered. Inevitably, when the share of RES reaches a certain level, there will be moments when more energy is available than needed and vice versa. The most common approaches to deal with excess electricity are:

- Reducing fossil fuel generation: this is the traditional approach and works well as long as these units are fast enough in changing their power output. Base load generators (typically nuclear and coal) are too slow for following RES fluctuations, whereas intermediate and peaking units (hydro and gas turbines) are fast enough. Fluctuating generation, like fluctuating load, also reduces efficiency, because the power plant is forced to work away from optimum design conditions.
- Load shifting: part of the electricity consumption can be shifted for increasing the demand during a certain period of time. This is practically implemented through energy market policies and requires the presence of shiftable loads.
- Storage to shift production: Energy storage can be introduced both at production and consumption sites. Similarly to load shifting, production shifting is motivated by the energy market framework.
- Introduction of new loads: Substitution of electrical loads for end-uses traditionally met by other energy carriers, such new loads include heating and electric vehicles.
- Power spill: excess power is not utilized at all. This is done when none of the above methods are applicable because of technical or economic constraints.

Many studies of high-penetration renewables assume that generation should never exceed load [4,6]. This may be expressed as never having excess at any one moment, or, in models with storage, that the yearly total generation should not exceed the yearly total load, storage being used to transfer energy from times of excess to times of deficit. However, such constraints on maximum generation do not consider whether this limit is cost effective. More recently, a few studies have recognized that excess renewable generation can be used to reduce the need for energy storage capacity [5,7,9], and because loss of revenue from excess generation may be less expensive than the cost of storage, the excess generation configurations can reduce electricity costs [7,9]. Heide [5] obtains figures for a fully renewable electricity scenario in Europe by studying how the amount of excess generation relates to the need for expensive storage capacity. Budischak [7] performed

Table 1
Main figures for the electricity sector in Europe (2006) and PJM (2002).

	EU 2006 [5]	PJM 2002 [7]	Units
Total annual consumption	3240	276	TW h_{el}
Average load	370	32	GW_{el}
Installed capacity	704[a]	72	GW_{el}

[a] Values for 2004 [10].

simulations to find the least-cost combination of renewables and storage for the PJM[1] area, finding that excess renewable generation can reduce the total cost of electricity.

2. Motivations

Depending on the quantity and time distribution of excess of electricity production, different options are available. As mentioned in the background section, excess power may be used to meet loads that are traditionally met by other energy carriers. In particular, heating requirements show a good potential for being met by electrical heating. One reason is that heating demand can be high enough to accommodate large amount of energy. Second, heat is inexpensive to store on site and can be controlled as part of existing building heating systems, making time of heat storage flexible in time. Finally, there is often good seasonal match between wind power production (more abundant during winter time), and heating requirements. Despite these advantages, a quantitative analysis is required to determine whether this option is economically feasible.

Budischak et al. [7] examined the potential of electricity overproduction to displace natural gas (NG) for space heating (SH) and domestic hot water (DHW). Results from [7] show a remarkably good match between months of excess electricity generation and months of heating demand. This is because their least-cost model selected predominately wind power for generation, and the winds are most energetic in cold months. Similar findings arise when comparing results from a fully renewable scenario in Europe [5] to the total heating requirement (both studies assume fully-built out transmission). Drawing from these two studies, Table 1 shows key data for the electricity sector in Europe as of 2006 and PJM as of 2002. The potential of excess power with respect to covering the heating demand in these regions is presented in Table 2. It shows results from simulated scenarios, comparing Heide et al. [5] with Budischak et al. [7]. Both scenarios find that cost minima lead to systems with significant excess electricity generation. In the European study, excess energy amounts to 50% of the total annual consumption if the total storage size is to be minimized in a 100% renewable penetration scenario. In the PJM study, the excess energy was 106% of the total annual consumption in a scenario with 95% renewable penetration[2] where the total cost of electricity was minimized. The amount of excess generation that comes from these simulations is comparable to the thermal energy demand in the residential and commercial sectors, as shown in Table 2.

It can be seen that, in scenarios like the ones presented in Table 2, a large part of the thermal energy requirements (36% and 71% respectively) could be met by excess renewable electricity, if the excess electric production can be matched in time to thermal load required. If electricity is converted to heat by means of heat pumps instead of direct resistive heating (Joule heating) these values can be increased by a factor of 2 or more, leading to a possible full coverage of the heat demand by excess electricity. Providing heat by means of renewable overproduction would be of extreme importance for the energy system. According to Table 2 the final use of thermal energy is circa 150% of the electricity consumption. Power and heat generation together accounted for more than 50% (40% and more than 10% respectively) of carbon emissions worldwide in 2008 [11].

These figures suggest a potential for using excess electricity to meet heat demand. However, such annual and monthly energy balances do not reflect the actual potential because the times of excess renewable power generation are not time matched to times of thermal requirements. Thus, a simple comparison of excess monthly generation to monthly thermal load, as done in [7], will likely overestimate the potential. Here a more precise calculation is performed: time steps of 1 h are distinguished, thus taking into account the temporal mismatch between excess electricity and thermal load. This approach will allow the optimal system design size parameters to be determined more accurately. Furthermore, the cost of such a system is estimated and compared to the cost of traditional heating supply. Otherwise, it could be that this approach is technically feasible, but not economically feasible. Finally, heat pump is compared with resistive heating.

This study aims to investigate the potential of large scale heating by means of excess electricity in a more accurate way. The total cost of heating in the PJM area during a period of 4 years was simulated and the parameters of the economically optimal heating system were estimated.

3. Methodology

This study compares two different types of heating system powered in part by excess renewable electricity. In each case, a direct natural gas heater in the building is used as a backup, thus it is not necessary to size the storage system to span the longest cold stretch. Two additional possible alternatives to the NG backup, not taken here, would be to eliminate the NG building heater and to either require storage large enough to meet the longest gap or draw from market electricity (non-excess electricity) when more heat is needed.

The first heating system type is shown in Fig. 1. Here, centralized or neighborhood heat pump based district heating (HPDH) plants convert excess electricity to heat and deliver it via a hot water distribution system to the final user, shown in Fig. 1 as Q_{load} within the Household. Household natural gas fired boilers (NGB) are used when the thermal load cannot be met via excess renewable electricity driving the HPDH. Conversely, when excess electricity exceeds thermal needs, thermal energy storage (TES) in the form of large water tanks is coupled to the HPDH in the centralized HPDH plant, and used to accumulate thermal energy. Constant efficiencies are associated with the TES, the district heating distribution network (DHDN), and the NGB. The HP converts electricity to heat with a constant coefficient of performance (COP).

Fig. 2 shows the second heating system type assessed in this study. Here, excess electricity is distributed to households instead of heat and converted locally to heat with a constant efficiency of 100%, that is, using resistive heating (*R*). The model assumes that thermal storage is installed on-site in each residence unit. In this model, high temperature[3] thermal storage (HTS) was chosen as resistive heating inherently has very high temperatures, thus a small

[1] PJM Interconnection (shortened here to "PJM") is a Transmission System Operator (TSO) covering 13 states in the North-Eastern United States (see Tables 1 and 2 for electrical characterization).

[2] In [7] the authors distinguish their three cases according to the percentage of hours during which all load is covered by renewable generation. Results presented here refer to the case with 90% of hours covered entirely by renewable generation, which corresponds to 95% of the total energy consumption.

[3] Here, TES is used to denote large installations with a median temperature below 100 °C, also referred as low temperature storage. By contrast, HTS denotes high temperature thermal storage up to 1000 °C or above.

Table 2
Results from simulated scenarios by Heide [5] and Budischak [7]. Values for EU refer to a case with hydrogen storage (36% round-trip efficiency), 50% excess electricity and wind power accounting for 70% of the total generation. Values for PJM refer to 2008 prices, 95% renewable penetration and batteries as storage. Energy values are annual totals.

	EU @ 100% RES	PJM @ 95% RES	Units
	Min storage size	Min electricity cost	
Total annual average renewable generation	4860	569	TW h_{el}
Total annual average electrical consumption	3240	276	TW h_{el}
Total renewable installed capacity	2130	156	GW_{el}
Installed storage capacity	50	0.145	TW h_{el}
	220	29	GW_{el}
Excess energy	50	106	% Annual consumption
	1620	293	TW h_{el}
Thermal energy load for SH and DHW (res & com)	4500[a]	433[b]	TW h_{th}
Thermal/electricity consumption	1.39[a]	1.56[b]	(Dimensionless ratio)
Excess gen/thermal req	0.36[a]	0.71[b]	TW h_{el} TW h_{th}^{-1}

[a] Total heat demand for EU25 in 2004 (deducted from [10]).
[b] Demand for SH and DHW production (value calculated by the author, see Section 4.2).

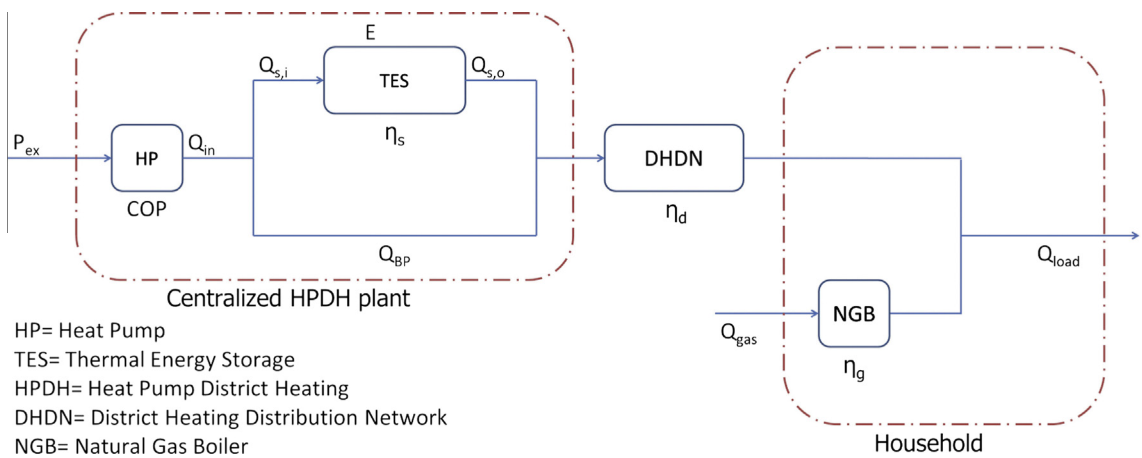

Fig. 1. Centralized district heating system design based on heat pumps (Q_{in} = COP · P_{ex}) and large thermal energy storage.

space (3–6 m^2) can store a few days of heat for an individual residence. Compact HTS household units based on ceramic bricks are available commercially.

If compared to heat pump heating, the advantage of HTS is that neither thermal distribution across buildings nor large volume thermal storage is needed. These infrastructures have some environmental and social impact, especially if retrofitted, require long periods to be implemented if installed only with new communities, and (especially for the DHDN) are responsible for a large part of the total cost. On the other hand, resistive heating is extremely inefficient from an exergetic point of view, compared to heat pumps. Electricity is converted to heat with a one to one ratio in the case of electric resistance while by using a heat pump about three units of heat are obtained from one unit of electricity. Thus, if there is a charge for excess electricity, as it is assumed here, the fuel cost for resistive heating is higher. Furthermore, backup gas fired units have to be turned on more often (when excess electricity is not sufficient) and related installation and running costs will rise. We did not model the cost of possible electrical transmission and distribution upgrades; some of which may be required, more so for the HTS than TES due to higher winter peak load for resistive heating. Indirectly this extra cost can be included in the excess electricity cost, which is modeled as a variable in this study (see Section 5).

The analysis spans over 4 years, for which real weather, electric load, and heating data were available. The model input are two time series data sets, hourly sampled for the years 1999–2002: available excess electricity (P_{ex}) and aggregated thermal load (Q_{load}). The data series for P_{ex} was provided by Budischak and represents the excess electricity from the RREEOM[4] model [7], which would otherwise remain unused. A calculation of Q_{load} was based on several data sets: ambient temperature (hourly sampled) for which we also had load data[5], NG consumption data [12] (monthly sampled), fuel share coefficients (the share of natural gas for space heating) [13], population, and PJM geographical share (data are available on a state base but some of them only partly belong to PJM). An alternative analysis would have used a typical meteorological year. However, actual data on meteorology corresponds with electrical and heating load, whereas there is no electrical load data corresponding to the fictitious TMY. Also, multiple years of actual data, as used here, are preferable over TMY as the size of the needed storage system is dictated by the longest low-energy period, better found in multiple years of real hourly data.

An algorithm that performs two tasks was developed; first, it calculates the energy balances hour by hour throughout the 4 years' time horizon. Secondly, it calculates the average cost of the heat supply (€$_{MW\ h,th}$). Fig. 3 shows the input and output of the algorithm and the dispatch strategy. Note that the maximum size of the thermal storage (E_{max}) and heating device (P_{max}) are

[4] The RREEOM model is the algorithm used by Budischak for simulating the high renewable penetration scenarios in [7].
[5] The weather data was an average of hourly ambient temperature calculated for each state across the PJM region. This was carried out by Deanna Sewell, based on US National Weather Service data.

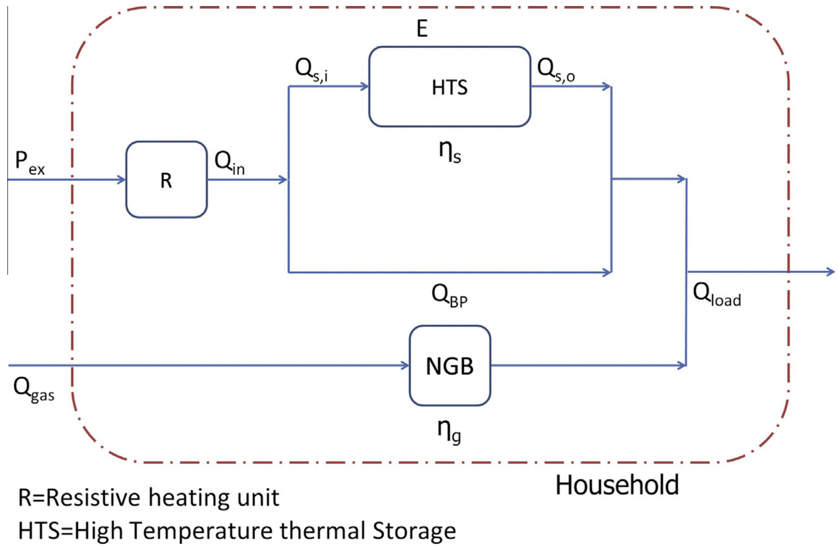

Fig. 2. Distributed household heating system design, using resistive heating ($Q_{in} = P_{ex}$), storage in each household, and high temperature storage (HTS).

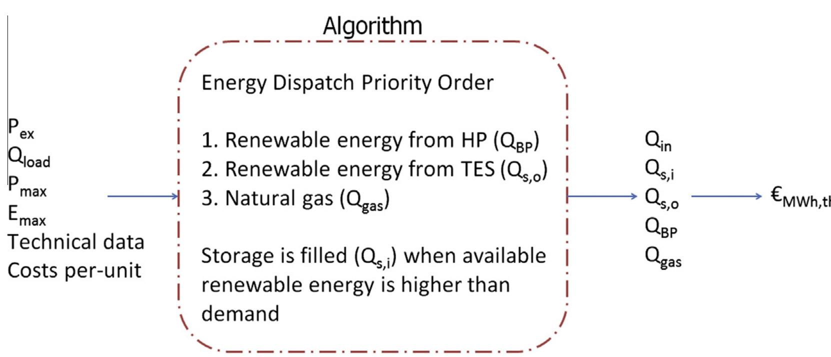

Fig. 3. Algorithm structure with inputs, outputs, and rules.

fixed, later in this article these are varied to seek the cost-optimum.

In order to cover different scenarios for the electricity and natural gas prices, different values of these variables were compared. Two simulations were run for each combination of electricity and natural gas price, one for each heating system concept. The influence of the electricity and natural gas price on heating costs, system design choices, and fossil fuel replacement has been studied.

The algorithm dispatches the available renewable energy at each hour according to the priority order presented in Fig. 3 and ensures that the thermal load is met. A constraint was applied in order to keep the energy content in the storage within its limits. This means that heat cannot be transferred to and from the storage if its energy content is higher than the maximum value (E_{max}) or lower than zero. Likewise, the excess power consumption of the heating system has an upper limit (P_{max}) given by the HP or R power rating and it cannot be negative.

Five cost centers (k) are associated with the main components (HP, R&HTS, DHDN, TES, and NGB)[6] of the heating system and their installation (I), interest payback and maintenance (OM) is calculated. Electricity and natural gas consumption are given a fixed price (respectively €$_{el}$ and €$_{NG}$). An interest rate (r) of 8% is used and the payback period for each cost center is assumed to be the lifetime (z) of the individual component.

For each simulation, the total average annual cost (€$_{year}$) was determined (1) as well as other indicators, such as the cost for a delivered unit of heat and its share among each cost center k:

$$€_{year} = \left(\sum_k \frac{r}{1-\frac{1}{(1+r)^{z_k}}} I_k + OM_k\right) + \sum_{1999}^{2002} \frac{Q_{gas}}{4} €_{NG} + \sum_{1999}^{2002} \frac{P_{ex,used}}{4} €_{el} \quad (1)$$

where $\sum_{1999}^{2002} Q_{gas}$ is the gas consumption 1999–2002 and $\sum_{1999}^{2002} P_{ex,used}$ is the excess electricity consumed throughout the 4 years.

The optimal design parameters of the system shown in Figs. 1 and 2 were also determined. The algorithm assumes that environmental, technical, and economic figures are constant and performs a sensitivity analysis on the electricity driven heating units and storage sizes. Heat pump and resistive heating unit sizes (measured by input power) varying from zero (no electricity heating units installed) up to the peak value of the excess electricity are assessed (using values beyond this limit would mean oversizing the units, that is, above that size would not bring any benefit in absorbing excess generation). For the DHDN concept, the sensitivity analysis on thermal storage capacity extends from zero (no storage installed) up to 10 days of maximum thermal load. For the resistive heating concept, the sensitivity analysis on the

[6] Note that only one cost center is used for addressing the total cost of HTS and R. This is because resistive high thermal storage is sold in units with fixed power to energy ratio, as shown in Table 7.

heating unit and storage size has to be performed only on one of these two variables (the R size was chosen for convenience) because the storage size is linked to the input power level (see Table 7). A cost matrix has been determined and the optimum values of P_{max} and E_{max} – those values resulting in the lowest heat production cost – have been found.

4. Input data

The algorithm described in Section 3 and graphically shown in Fig. 3 requires different types of input data: technology specifications (efficiencies and loss rates), costs per-unit, and the energy data series (hourly excess electricity and thermal load). This section presents the input data that were used for the simulations and their sources.

4.1. Technology specification and costs

To each of the main components of the simulated heating system sketched in Figs. 1 and 2, costs and efficiencies were assigned. In this section, data for different technologies are summarized in tables, one for each component. The last row in each table shows the values used in the simulations. Blank entries mean that data are either not applicable or not available. The sources include study cases and figures found in literature (data from different sources were converted to the same units). The main assumptions behind these calculations are also briefly presented. For many of the technologies, several models and types were available. The choice among different types, was made under technological constraints, but often several options would be suitable. Given the remaining variety in technology, specifications and prices, to create technology inputs required some judgment calls and choice of median or common values by critically assessing the available data and making the best judgments—resulting in the "used in simulation" bottom line values in Tables 3–5.

Heat pump technology data are shown in Table 3. Installation costs are given in $\$kW^{-1}$ and operation and maintenance costs are given in $\$kW^{-1}$ $year^{-1}$. The choice of heat pump was based on two requirements. Large installations were considered, in order to be able to satisfy the large thermal demand of a district heating plant. A second requirement was high temperature of the supplied heat. This choice allows for maintaining the present heating equipment in households – such as radiators – that usually work at high temperatures. In turn, relatively low COP values had to be assumed. Given the similar installation costs in Table 3, it is plausible that more efficient heat pumps that work with steady temperature heat sources would be the first choice when possible and only a limited number of ambient source heat pump would be installed. Thus, the chosen installation price, an intermediate value 7% higher than the average for a sewage water heat pump, was a conservative assumption. Considering that few air source heat pumps are used in the model, COP dependence on ambient temperature was not modeled.

Technical and economic data for thermal storage are listed in Table 4. When possible, the location and volume of the installations are also given. Cost figures, if not already given in this fashion, were brought back to $\$kW\,h^{-1}$ by assuming that 1 m^3 of thermal storage can hold 60 kW h of thermal energy. Yearly operation and maintenance costs are given as a percentage of the initial TES investment costs. The constant heat loss rate of thermal storage is given in percent of E_{max} per hour.

Table 4 shows that cost figures for thermal energy storage depend on the size of the installation. Similarly to the HP technology choice, here it was assumed that a mix of different technologies and volumes contribute to make an aggregated component. An intermediate cost was chosen that reflects a hypothetical installation, sized between seasonal storage and large water tanks.

Costs and efficiencies for district heating networks are summarized in Table 5. Installation and yearly operation and maintenance costs were brought back to $M\$TW\,h^{-1}$ $year^{-1}$ and percentage of the initial DHDN investment costs respectively (if not already given in this fashion). Calculations were based on the following assumptions. When data values were dependent on the total energy delivered, all the heat demand was assumed to be satisfied by district heating (no natural gas back-up). For data found in per-dwelling, a value of three persons per-dwelling was used. The

Table 3
Heat pumps technology data (blank if datum not given in source).

Source	Technology	Installation $\$kW^{-1}$	O&M $\$kW^{-1}$ $year^{-1}$	COP	Life years
[14]	Refrigerant: R134a[a]	794		3	
[15]	Refrigerant: CO_2[b]	676	4.8	2.8	20
		1092	9.5	2.8	20
Used in simulation		854	7.1	3	20

[a] Heat source: sewage water @ 10 °C, Heat supply @ 90 °C.
[b] Heat source: ambient air, Heat supply @ 80 °C.

Table 4
Thermal storage technology data (blank if datum not given in source).

Source	Technology	Site	Volume m^3	Installation $KW h^{-1}$	O&M % of investment pr. year	Heat loss rate % of E_{max} pr. hour	Life years
[15]	Seasonal	Friedrichshafen	12,000	2.5			
[15]	Seasonal	Potsdam	35,000	1.1			
[15]	Seasonal	Dronninglund	60,000	0.7	0. 7		
[15]	Seasonal	Munich	5700	3.5			
[15]	Seasonal	Stuttgart	700	4.2			
[15]	Large tanks		4000	3.3		0.03	
[15]	Large tanks		1000	4.8		0.03	
[15]	Large tanks		2000	3.4		0.03	
[15]	Large tanks		10,000	4.6		0.03	
[16]	Small tanks		400	7.5			
[17]	Small tanks			3.5	0. 7		
Used in simulation				3.0	0.7	0.03	35

Table 5
District heating networks technology data (blank if datum not given in source).

Source	Technology	Investment M\$TW h^{-1}	O&M % of investment pr. year	Efficiency %	Life year
[18]		2188			
[19]	twin pipes urban DHDN excluding branch pipes	94	1	85	30–50
[19]	twin pipes urban DHDN including branch pipes	245	1.3	85	
[17]		86	1		
[20]	including branch pipes including hydraulic system (end user)	413			
[21]		248			
[22]	sparse	967			
[23]	low heat demand	193		75	
[23]	low heat demand	339		75	
[24]				87	
[25]				90	
Used in simulation		200	1	90	30

Table 6
Natural gas fired boiler technology data (blank if datum not given in source).

Source	Technology	Cost $\$kW^{-1}$	O&M $\$kW^{-1}$ $year^{-1}$	Efficiency % of LHV	Life time years
[19]	Household	260	5.2	102	22
[26]	Household	146		107	15
[26]	Household	248		107	15
[20]	Household	160	16.0	91	15
[20]	District heating	96	4.8	85	30
Used in simulation	Household	200	10.6	100	16

value calculated from [18] is found to be more than two times higher than all other entries of Table 5. The author presents a formula based on the area covered by the DHDN and the delivered energy. This area was assumed to be 3% of the total PJM area and the table-value has therefore been obtained by extrapolation.

The chosen figures for DHDN reflect a realistic scenario with a very high penetration of district heating that allows for relatively low installation costs and high efficiencies. Again, the aggregated distribution network will consist of a mix of different technologies with the average characteristics of the bottom row of Table 5.

Technological and economic data for natural gas fired boilers are listed in Table 6. When needed, a 25 kW unit installation was assumed for the calculations. Efficiency values above 100% of the lower heating value (LHV) of NG are used for condensing boilers, because they recover the latent evaporation heat of the water produced by the combustion process.

Apart from the entry referring to large district heating units, figures from Table 6 fall in a narrow range. Hence, a mean value of the household units was used for calculations.

Resistive heating technology data are shown in Table 7. Sources gave the installation costs of commercially available systems in $\$furnace^{-1}$. High temperature electric heating is available in modules suitable for rooms or entire homes. In Table 7 some of the available sizes for whole homes are listed. The same resistive technology is available to be installed as an air only system (forced air furnace) or as hydronic space heating equipment. An intermediate size of 28.8 kW_{el} input power and 180 kW h_{th} energy storage of the latter installation was chosen as reference in this study. The heat loss from the high temperature storage was set to 0% as the value was not given by the manufacturer and, heating system losses may be minimal since, for in-building systems, the heat transfer occurs from storage to the heated space.

In this study, the value of excess electricity used for heating is a model variable and was set to 0.10 $\$kW\,h^{-1}$ and 0.05 $\$kW\,h^{-1}$, with a third case of 0 $\$kW\,h^{-1}$ (no value) for the excess electricity consumption, the latter considered as the reference case.

As for comparison, electricity production cost from Budischak et al. [7] spans from 0.23 $\$kW\,h^{-1}$ to 0.15 $\$kW\,h^{-1}$. These values come from a model for 95% of electric energy from wind and solar, with central batteries as storage (the most expensive storage assessed) and installation costs in 2008 and 2030, respectively. Also, Budischak et al. optimized the least-cost system assuming no value for excess electricity (they subsequently modeled the use of excess electricity for resistive heating, valuing it at the cost of natural gas).

The NG price was also used as a model variable in this study. Its values were set to the current price (assumed to be 0.04 $\$kW\,h^{-1}$), to 0.08 $\$kW\,h^{-1}$, and to 0.16 $\$kW\,h^{-1}$. This is because NG prices are

Table 7
Resistive heating and high temperature thermal storage units technology data (blank if datum not given in source).

Source	Technology	Input power kW	Storage size kW h	Installation $\$furnace^{-1}$
[27]	Residential hydronic furnace	14	120	5375
[27]		28.8	180	6030
[27]		45.6	240	6490
[27]	Residential forced air furnace	14	120	4640
[27]		28.8	180	5250
[27]		45.6	240	5710
[28]		14		5644
[28]		30		6563
[28]		45		7481
Used in simulation		28	180	6030

likely to increase in future scenarios, even considering the increasing in shale gas production included in recent projections [29]. The study does not model the environmental costs of CO_2 emissions, which may be added on as a carbon tax or other fee added to natural gas prices. Charging for CO_2 emissions is nowadays a common policy for incorporating externalities, which also has the effect of incentivizing renewable generation and reducing the use of fossil fuel. Although CO_2 taxes would favor renewable energy, the effect may be small compared to the volatility of the NG price itself. For example, CO_2 tax rates applied in British Columbia in 2010 were in the range of 10% of the current NG price [30], while in 2008 the NG price was approximately 300% above its current value [31].

4.2. Excess electricity and thermal load

As previously mentioned, the applied algorithm relies on two data sets: thermal load and excess electricity. This section clarifies how these data were obtained.

Unlike electricity, thermal demand is not generally available as an aggregated and hourly sampled data set. Unlike electricity, there is not a large system operator for thermal energy, who measures and records data systematically hour by hour. Data for thermal load (Q_{load}) were developed indirectly, so this required a number of assumptions and calculations. Two sets of data are the basis for addressing this task: hourly sampled ambient temperature and monthly NG consumption ($Q_{NGmonth}$) for the commercial and residential sectors. The outdoor temperature was used for determining the hourly profile of the heating load. The NG consumption was used for calculating the monthly heating demand (Q_{month}).

For each state (i) within PJM, the total heating load was calculated as the sum of two terms (2). The first term, which is linearly dependent on ambient temperature, was calculated using the degree-hours technique and meant to represent the space heating demand (Q_{SH}). The second term, which represents the domestic hot water consumption (Q_{DHW}), was assumed to be independent on the ambient temperature and to follow predetermined seasonal and daily patterns [32].

$$Q_{i,load} = Q_{i,SH} + Q_{i,DHW} \tag{2}$$

Monthly thermal requirements were calculated (3) from natural gas consumptions, taking into account the share (φ) of natural gas in SH and DHW and the percentage (ψ) of natural gas used for SH and DHW purposes [13].

$$Q_{i,month} = Q_{i,NGmonth}\psi_i/\varphi_i \tag{3}$$

The proportionality factor ($\alpha > 0$) between the degree-hour values (DH) and the space heating requirement (4) had to be determined. For this purpose, a minimization problem was set up (5) in order to find the value of α that leads to the smallest difference between the calculated load (based on the ambient temperature and α) and the monthly heating demand related to the NG consumption over the simulation time horizon of 4 years (35064 h for the total load Q_{load} or 48 months for the monthly heating demand Q_{month}).

$$Q_{i,SM} = \alpha_i DH_i \tag{4}$$

$$\min_{\alpha}\left\|\sum_{t=1}^{35064} Q_{i,load}(t) - \sum_{m=2}^{48} Q_{i,month}(m)\right\| \tag{5}$$

The final load was determined as the sum of the state loads weighed according to the fraction of each state's area within PJM (6). γ is the ratio between the area of a state within PJM and the total state area.

$$Q_{load} = \sum_i Q_{i,load}\gamma_i \tag{6}$$

The excess electricity data set was provided by Budischak [7] as an output from the RREEOM simulation using 2008 prices, 90% of hours (95% of energy) covered by renewable energy and central batteries as electricity storage. Fig. 4 shows space heating demand Q_{load} and excess available electricity P_{ex}, for the simulated time horizon of 4 years for the entire region. P_{ex} is essentially the amount of heat available via electric resistance heating from excess electricity. The thermal demand Q_{load} follows a typical pattern of space heating combined with domestic hot water supply in a continental climate (PJM). The thermal load is high during winter when space heating is needed and lower during summer, when only DHW has to be supplied. Excess electricity has also been converted to heat (multiplied by the HP coefficient of performance COP) and shows more than enough heat from excess electricity all year. Both heat graphs show lower availability in summer, when excess electricity is lower because wind power is less and cooling loads (electricity driven HVAC systems) are high.

As Table 2 and Fig. 4 suggest, a high percentage of the thermal load can be covered by excess electricity, with a substantial margin of extra heat supply if a heat pump is used. Furthermore, seasonal variations of both excess electricity and thermal load show a similar trend with higher values during winter.

However, if a shorter timescale is considered, as shown in the 5 days graphed Fig. 5, it is seen that the mismatch between thermal load and excess electricity can become significant. Here, as in the prior Fig. 4, no storage is modeled. For example, during a two and a half day period (from January 8th through the morning of January 10th 2000) the excess electricity is insufficient to meet thermal demand—for over 24 h it is even zero, far below the thermal need of almost 100 GW. On the other hand, the two following days the excess power is higher than the thermal demand—at times heat pumps could produce from 2 times to six times the heating needs. This points out the importance of simulations with an hourly resolution, as it was done here, in order to capture

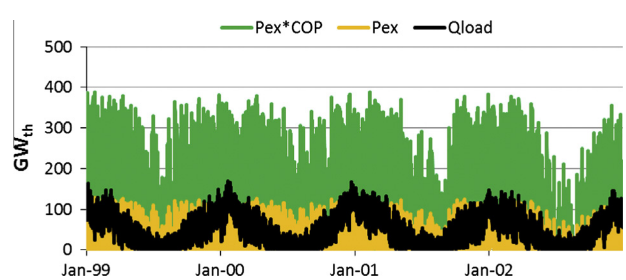

Fig. 4. Seasonal patterns of thermal load Q_{load}, excess electricity production as P_{ex} and available thermal energy after the conversion of excess electricity through a heat pump P_{ex}*COP.

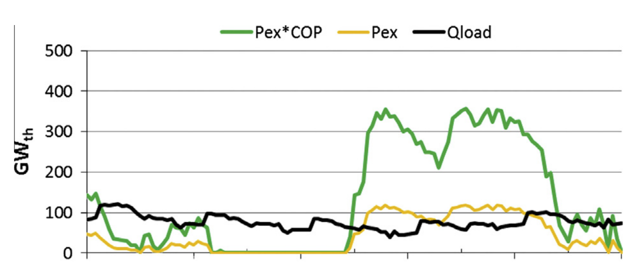

Fig. 5. Patterns of excess electricity P_{ex} and thermal load Q_{load} over a 5-day example period. The available thermal energy after the conversion of excess electricity through a heat pump P_{ex}*COP is also shown. The same color scale is used here as in Fig. 4.

mismatches that would not be seen in more aggregated time intervals such as daily or especially monthly. Furthermore, such large intra-day or intra-week mismatches illustrate that thermal storage could play a key role in meeting heat requirements from excess generation.

5. Results

This section presents the model outcomes from the study. First, the scope of the simulations is introduced (electricity and NG price scenarios, and two heating system types). Successively, an overview of the calculated heat production cost and design parameters for each scenario is given and results are analyzed. Finally, three HPDH scenarios with a fixed electricity price and variable cost of NG are compared in terms of sensitivity of the heat production cost to HP and TES size, excess energy utilization patterns, energy storage dynamics and use of natural gas.

In total 18 simulations were performed, covering all combinations of natural gas price, excess electricity price, and heating system type. The natural gas price was set to 0.04 $kW h^{-1} ($1.17 therm^{-1}, the approximate residential price in the US as this goes to press), 0.08 $kW h^{-1}, and 0.16 $kW h^{-1} (hence indicated as NG4, NG8, and NG16 respectively). The excess electricity price was set to 0.00 $kW h^{-1}, 0.05 $kW h^{-1}, and 0.10 $kW h^{-1} (the acronyms EL0, EL5, and EL10 are used for referring to each of these electricity price scenarios). Free excess electricity (EL0) was used as a reference case, if, for example, renewable producers are willing to give away power that would be otherwise spilled. If the electricity is sold, we used EL5 and EL10, where the producer charges something, perhaps to cover operational costs. Also, the chosen electricity price for EL5 and EL10 is high enough for allowing utility companies to make marginal profit. However, values lower than 0.23 $kW h^{-1} (the electricity production cost calculated by Budischak for the high-cost central battery case) were chosen for less valuable excess electricity. The heating system types assessed were heat pump and central low-temperature thermal storage, centralized with district heating, versus resistive heating coupled with distributed high temperature thermal storage in the building where the heat will be used (indicated as HP and R respectively). When referring to a particular simulation, the natural gas price tag will be used first, followed by the electricity price as second tag and the heating system as third. Thus, the acronym NG4-EL0-HP stands for the simulation that modeled a natural gas price of 0.04 $kW h^{-1}, an electricity price of 0.00 $kW h^{-1}, and the heat pump technology.

Tables 8 and 9 summarize the optimal economic design size choices of the heating equipment and thermal storage corresponding to the different combinations of NG price, electricity price, and heating system concept.

The cost per delivered unit of thermal energy varies from 34 $MW h$_{th}^{-1}$ for case NG4-EL0-R to 142 $MW h$_{th}^{-1}$ for case NG16-EL10-R. All the other combinations of NG, electricity prices and heating types return intermediate costs of thermal energy production.

If the cost of excess electricity is zero and natural gas is $0.04, the lowest cost system is the resistance with HTS in the residence (NG4-EL0-R). But for all other cases, when comparing the heating type only (NG and electricity prices being fixed), the lowest cost is district heating with heat pumps and centralized storage. Heating via HPDH is less expensive than resistive heating in all the simulated scenarios but NG4-EL0-R. One might think that the lowest cost would be for all scenarios in which fuel were free, but in the resistance scenarios, there is not enough excess electricity, so our heating model requires use of natural gas when there is not enough electricity – raising the cost and increasing the environmental damage. By contrast, the HP increases the useful heat produced from excess electricity, reducing the need for NG.

From an environmental perspective, the greatest reductions in CO_2 emissions can be determined by looking for the lowest numbers in the rows "Heating share from natural gas". For the heat pump systems, natural gas can be reduced to the level of 3% of heating need (NG16EL0HP), and with resistance heat, natural gas can be reduced to 40%. The low use of natural gas for heating happens more as the cost of excess electricity is lower and the cost of natural gas is higher.

Because of the cost competitiveness and lower CO_2 emissions of the HP based concept, the discussion of results below will mostly concentrate on this technology option.

Table 8 helps understanding what the effect of the natural gas and electricity price is on the optimum design choice, the use of excess electricity, and the relative costs associated with the main components of the heating system as well as with the utilities consumption.

The HP and TES design sizes vary from zero to 55 GW_{el} and from zero to 6.4 TW h_{th} respectively. As the NG price increases it becomes more cost-optimal to design a system with larger HP and TES installations. On the other hand, if the natural gas price is kept fixed, the optimum HP and TES design sizes tend to decrease when the electricity price becomes higher. The extreme case, when the NG price is the highest and the electricity is not charged, results in the largest HP and TES design sizes. Conversely, in scenario NG4-EL10-HP, with low natural gas price and high electricity price, the cost-optimum is no HP and no TES at all. In between these two cases fall the other intermediate combinations of HP and TES sizes. G4-EL5-HP is a particular case where the HP design size is small enough to not require any TES. This is understood because differing assumptions about price will lead to different relative use of natural gas and electricity for heating. Of course, when building an energy system, one must either make the best prediction, or from a public sector perspective, one must make policies to achieve the desired result; thus, it may be environmental or other considerations that determine, in particular, the price of excess electricity from a high-penetration renewables scenario.

Table 8 shows a tendency to larger heat pump and thermal storage being optimal when electricity prices are lower and NG prices are higher (and as consequence larger HP and TES installations). As an example, assuming 0.10 $kW h^{-1} as electricity price, HP associated costs vary from 0% (NG4-EL10-HP) to 14% (NG16-EL10-HP) of the total cost while from 0% (NG4 -EL10-HP) to 3% (NG16-EL10-HP) of the total cost is given by the TES.

The trend is reverse for NGB related costs (including gas consumption). At a high electricity price, these costs range from 100% (NG16-EL10-HP) to 21% (NG16-EL10-HP) of the total cost. If the electricity is free of charge less gas is burned and the maximum relative cost for the backup heating is 44% (NG4-EL0-HP). Notably, the relative cost of the backup heating is still above 20% even at the highest NG rates and zero electricity price (NG16-EL0-HP). In this case, natural gas boilers installation and maintenance account for 21% and gas consumption 11% of the total even though only 3% of the delivered energy comes from NG.

District heating distribution networks relative costs account for almost 40% of the total cost when the electricity is not charged. If the electricity price increases, this value tends to decrease falling between 20% and 27%. In cases NG4-EL5-HP and NG4-EL10-HP, where the HP size is very small or zero, distribution networks account for 9% and 0% of the total cost only.

Finally, the cost of the optimum system for each scenario was compared to the cost of a system that does not exploit HPDH and is based on household NGB only. Not surprisingly, as the price of natural gas increases, the relative cost of electric heating (compared to the gas only case) decreases. At NG price two times the

Table 8
Summary of main results for the heat pump based simulations.

Heating system	HP									
Natural gas price	0.04			0.08			0.16			\$kW h^{-1}
Electricity price	0.00	0.05	0.10	0.00	0.05	0.10	0.00	0.05	0.10	\$kW h^{-1}
Heat production cost	44	53	53	48	66	82	51	70	88	\$MW h$_{th}^{-1}$
HP size	34	6.8	0	54	40	34	55	55	55	GW$_{el}$
	26	5	0	42	32	26	42	42	42	% of max (P_{ex})
Storage size	2.1	0	0	4.3	2.1	2.1	6.4	4.3	4.3	TW h$_{th}$
	43	0	0	87	43	43	130	87	87	Hours @ mean (Q_{load})
	13	0	0	25	13	13	38	25	25	Hours @ max (Q_{load})
Use of excess electricity	44	12	0	51	47	44	53	51	51	% of available excess electricity
Heating share from natural gas	17	77	100	5	13	17	3	5	5	% of total thermal demand
Total cost HP	17	3	0	25	14	9	29	17	14	% of total cost
Total cost DHDN	36	9	0	39	26	20	37	27	22	% of total cost
Total cost NGB + NG consumption	44	80	100	30	33	31	33	26	21	% of total cost
Total cost NGB (I and O&M)	27	22	25	23	18	14	21	16	12	% of total cost
Total cost NG (consumption)	16	58	75	8	15	17	11	10	8	% of total cost
Total cost TES	3	0	0	6	2	2	11	4	3	% of total cost
Total cost electricity	0	8	0	0	25	38	0	26	41	% of total cost
Electric/NGB-only cost	82	100	100	52	71	88	29	40	51	Dimensionless ratio

Table 9
Summary of main results for the resistance heating based simulations.

Heating system	R									
Natural gas price	0.04			0.08			0.16			\$kW h^{-1}
Electricity price	0.00	0.05	0.10	0.00	0.05	0.10	0.00	0.05	0.10	\$kW h^{-1}
Heat production cost	34	53	53	50	80	93	82	112	142	\$MW h$_{th}^{-1}$
HP size	88	0	0	100	75	0	116	109	95	GW$_{el}$
	68	0	0	79	58	0	89	84	74	% of max (P_{ex})
Storage size	0.6	0	0	0.6	0.5	0	0.7	0.7	0.6	TW h$_{th}$
	11	0	0	13	9.5	0	15	14	12	Hours @ mean (Q_{load})
	3.3	0	0	3.8	2.8	0	4.3	4.0	3.5	Hours @ max (Q_{load})
Use of excess electricity	84	0	0	87	80	0	88	87	86	% of available excess electricity
Heating share from natural gas	41	100	100	39	44	100	39	39	40	% of total thermal demand
Total cost *R*	18	0	0	14	6	0	10	7	5	% of total cost
Total cost NGB + NG consumption	82	100	100	86	59	0	90	66	53	% of total cost
Total cost NGB (I and O&M)	34	25	25	23	15	14	14	11	8	% of total cost
Total cost NG (consumption)	48	75	75	63	44	86	76	56	45	% of total cost
Total cost HTS										% of total cost
Total cost electricity	0	0	0	0	35	0	0	27	58	% of total cost
Electric/NGB-only cost	65	100	100	54	87	100	47	65	83	Dimensionless ratio

current, it would be possible to reduce the heating cost by approximately 20–30%, depending on the electricity price. Larger savings would occur if the NG price goes up to four times the current level. In this case the reduced use of natural gas falls in a range within 50% and 70%.

In Fig. 6 the final cost of a unit of heat is shown for all the different combinations of P_{max} (from zero to the maximum value of the excess electricity $P_{ex,max}$) and E_{max} (from zero to 10 days of the maximum value of the thermal load $Q_{load,max}$) in the different NG price scenarios and for the HP system with the electricity price set to 0.10 \$MW h$_{th}^{-1}$. This figure can be used to determine the optimal size of storage and of reloading power. The optimum costs in Table 8 were calculated based on these cost matrices and are indicated in Fig. 6 by a diamond. The cost scale bars on the right hand side of the plots indicate the heat production cost. The irregular pattern of the plots in Fig. 6 can be explained by considering the different sources of cost. Costs related to the HP and TES units vary linearly along the *y* axis and *x* axis respectively. In contrast, the costs associated to the distribution network, the electricity consumption and backup heating do not depend directly on P_{max} and E_{max} and cannot be easily predicted from these two values.

With reference to Fig. 6, at current NG prices it is possible to achieve minimum costs around 53 \$MW h^{-1}, as also shown in Table 8. In the two remaining scenarios, with higher NG prices, the minimum cost of a unit of heat falls in the range between 80 \$MW h^{-1} and 90 \$MW h^{-1}. The design HP and TES sizes, which give the minimum cost, increase with the price of natural gas. It is graphically shown in Fig. 6, where the red diamond indicating the design values moves upwards (HP size increases) and to the right hand side of the plot (TES size increases). In scenario NG4-EL10-HP, installing any heat pump or thermal storage will result in a higher heating production cost due to the low price of the natural gas and the high price of electricity. At higher NG prices the cheapest choice always requires some HP and TES to be installed. The optimum design sizes for scenario NG8-EL10-HP are 26% of $P_{ex,max}$ (heat pump) and 13 h of $Q_{load,max}$ (storage). Larger HP (42% of $P_{ex,max}$) and TES (25 h of $Q_{load,max}$) installation are needed to optimize heat production costs in scenario NG16-EL10-HP.

From Fig. 6, the maximum cost was calculated to be 120 \$MW h^{-1} for both scenario NG4-EL10-HP and NG8-EL10-HP while it reaches 200 \$MW h^{-1} in NG16-EL10-HP. At low NG rates, higher costs are obtained when too much HP and TES is installed. However, in scenario NG16-EL10-HP, the highest costs are given by HP and TES combination that are too small to exploit excess electricity which in this scenario is more competitive than NG. This is shown in Fig. 6, bottom graph. Here, if the HP installed is less

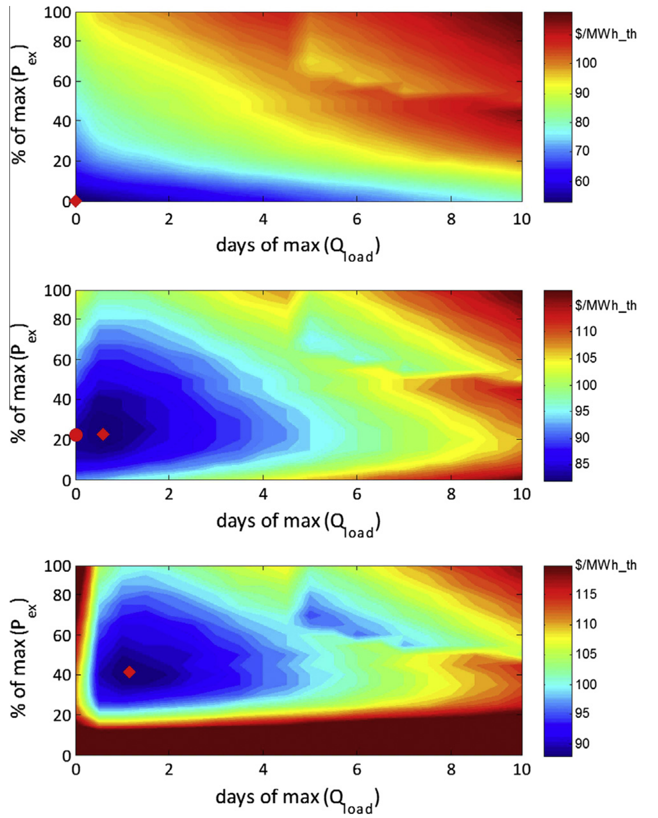

Fig. 6. Cost graphs for scenario NG4-El10-HP (top), NG8-El10-HP (middle), and NG16-El10-HP (bottom). The scale bar on the right indicates the total annual cost in $MW h_{th}^{-1}. The red (light grey in greyscale renditions) is high cost at upper right of all three diagrams and the bottom of the lower diagram. The blue (dark grey in the greyscale rendition), where the diamonds are, is the lowest cost. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

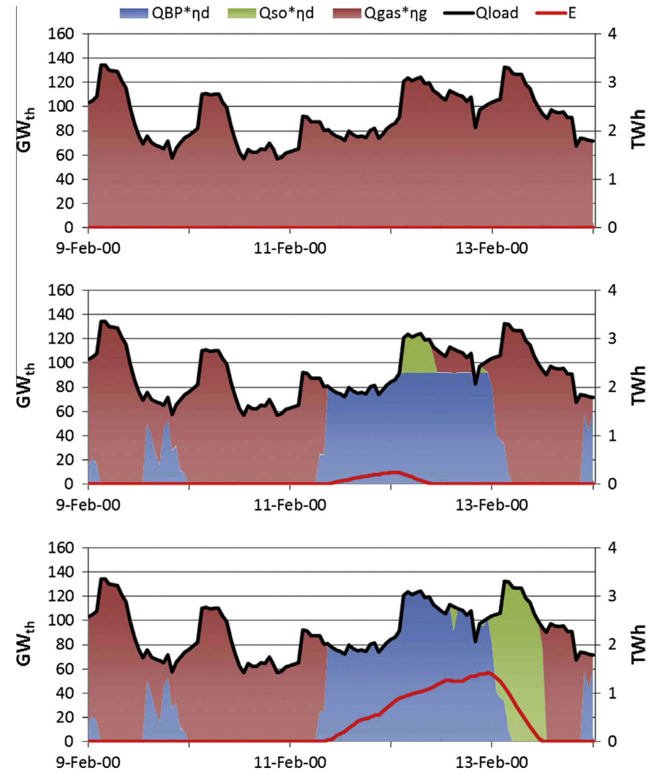

Fig. 7. Heating load share by source over 5 days. From top to bottom, the three figures refer to scenarios with NG4-El10-HP, NG8-El10-HP, and NG16-El10-HP. The price of electricity (10¢kW h^{-1}) is kept constantly high among the plots, and the price of natural gas becomes more expensive as we move from top to bottom.

than 15% of $P_{ex,max}$, the heat production cost rises above 120 $MW h^{-1} and goes up to 200 $MW h^{-1} while the amount of HP installed decreases.

An important result was found when comparing heat production costs and natural gas consumption at different amount of storage installed. Referring to the middle plot of Fig. 6, the round marker on the Y axis indicates a scenario where the installation of heat pumps is the same as the design choice (34 GW_{el}) for the given electricity and gas prices but no thermal storage is installed. As the color map suggests, the heat production cost is slightly higher than the optimum (84 $MW h^{-1} against 82 $MW h^{-1}). However, the consumption of natural gas of the optimum case is significantly lower. When no storage is installed, 35% of the required heating is supplied by natural gas, twice as much as the 17% natural gas in the optimum case, as shown in Table 8.

The implications of having larger equipment sizes are shown in Fig. 7, where some of the most important system variables for scenarios NG4-EL10-HP, NG8-EL10-HP and NG16-EL10-HP are plotted for the same 5 days as those in Fig. 5, a week that is challenging for storage. When excess electricity ($Q_{BP} \cdot \eta_d$) is not sufficient to cover the thermal demand, the thermal storage is first drained ($Q_{s,o} \cdot \eta_d$) and then fossil fuel is burned ($Q_{gas} \cdot \eta_g$).

In scenario NG4-EL10-HP, the topmost figure, all the heating is delivered by backup fossil fuel. Nevertheless, TES units are able to cover thermal needs for several hours, reducing the need for NG, like in scenario NG8-EL10-HP, where energy from the TES replaces a small fraction of the NG heating for a few hours. Scenario NG16-EL10-HP shows a larger part of the demand being supplied by heat from TES, which is two times larger than in scenario NG4-EL10-HP. However, during the examined period a large part of the load is still covered by gas. This happens because when there is no excess electricity available the storage is only partially charged (or empty) when it starts to operate. The benefit of having more installed storage is clear in the bottom plot that represents scenario NG16-EL10-HP. Here, $Q_{s,o} \cdot \eta_d$ is enough for meeting all the thermal demand during some hours on February 13th.

Larger HP installations also bring benefits to the system. In scenario NG8-EL10-HP, the HP can handle 34 GW_{el} (corresponding to heating 91.8 GW_{th} when converting to heat and subtracting distribution losses). This limitation is graphically visible as a blue step in the right hand side of the plot, where in the morning of February 12th, the heat injection from the HP is insufficient – even though there is enough excess electricity available – and energy is taken from storage. In scenarios NG16-EL10-HP the heat pump is large enough to satisfy the demand at this particular period of time and also capable of supplying heat to the TES.

The amount of heat stored in the TES in the three scenarios is shown in Fig. 8. Since at the lowest natural gas price no TES is installed, the dark line NG4 lays on the bottom of the plot with a constant zero value. When TES is installed, a typical storage pattern with state of charge cycles between minimum and maximum storage levels describes its dynamic. This chart also shows another aspect of the simulated energy system. As the storage increases in size, its utilization becomes less intensive. For example, the pattern of the 2.1 TW h storage in Fig. 8 shows many full cycles between 0 and 2.1 TW h, whereas the larger 4.3 TW h fluctuates over a narrower range and is seldom completely drained. In scenario NG8-EL10-HP, the TES is at its minimum energy level during 20% of the time and is filled 25% of the time. In scenario NG16-EL10-HP the TES is at minimum only 4% of the time and at maximum energy 35% of the time.

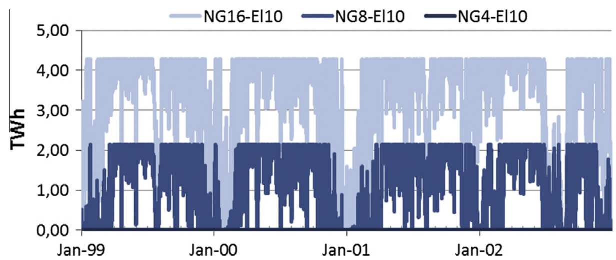

Fig. 8. Amount of energy (in TW h) in the thermal energy storage. The three colors compare three different natural gas prices, with the lowest cost of NG not using the storage at all, and thus shown as a black line at zero, along the bottom of the graph.

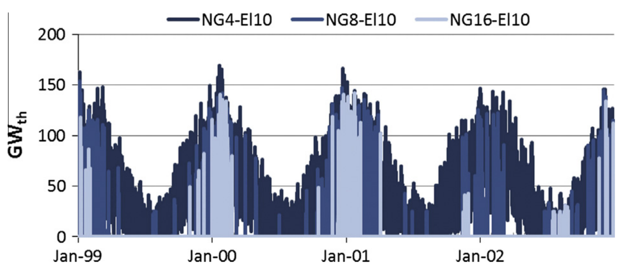

Fig. 9. Natural gas consumption for heating, for three different natural gas prices.

The seasonal use of NG is plotted in Fig. 9 for scenarios NG4-EL10-HP, NG8-EL10-HP, and NG16-EL10-HP. It shows that the NG back-up power needed is not proportional to the frequency of its use. During periods with a high ratio Q_{load}/P_{ex}, like January 2001, the height of the peaks of NG use is similar for the three scenarios, leading to similar NGB installation and maintenance costs. However, the total amount of fossil fuel burned changes considerably, as shown in Table 8.

6. Discussion

From environmental and political considerations, large deployment of renewable generation may occur due to strong policies to limit CO_2 from electric generation. In this case, there may also be policies to minimize CO_2 from building heat loads. A previous study of mid-latitude high-penetration renewables (PJM Interconnection) shows that the lowest cost combinations of renewables generation and electrical storage will result in excess electric generation [7]. The current study adds the previously-undocumented finding that the amount of excess is enough to meet all building heat needs if utilized via heat pumps, but not quite enough if turned to heat by resistive heaters.

Several combinations of natural gas (for backup heating) and excess electricity prices were assessed. In this section, the discussion of the results focuses on simulations based on the highest electricity price. As Tables 8 and 9 show, higher electricity prices result in smaller HP and TES installations on one side, and in larger NGB units and higher gas consumption on the other. The total cost for producing a unit of heat also increases with the electricity price.

It was found that heating with excess renewable electricity is generally more economical if achieved by installing centralized district heating based on heat pumps and large, low-temperature thermal storage, rather than installing household-level electric resistance heating with small high temperature thermal storage. However, from Table 7 it can be seen that the costs of resistive heating and high temperature storage are mostly for installing the unit, with a smaller amount for the size of the equipment. Thus, a better exploitation of high temperature storage technology would be installing larger units, sufficient for longer cold spells and/or can serve multiple households. This approach could potentially lead to lessen the heat production cost and make this technology competitive with the heat pumps. In practice, the choice between systems will also depend on regional differences; for example, in Northern Europe much of the district heating infrastructure is already in place, whereas neighborhood heat transfer would need to be added to most American or Asian residences. Furthermore, in any one region a mix of HTS and HPDH may be most practical depending on site-specific evaluation.

The modeled system is able to provide space heating and domestic hot water at a production cost of 53 $\$MW\,h_{th}^{-1}$ with the current NG price and the highest electricity price hereby assessed (NG4-EL10-HP). This cost increases up to 88 $\$MW\,h_{th}^{-1}$ if the price of NG is four times higher (NG16-EL10-HP). As for comparison, the average retail price of district heating heat in 2007 in Sweden was found to be about 100 $\$/MW\,h_{th}$ with a minimum of 60 $\$MW\,h_{th}^{-1}$, while in Denmark in 2009 the minimum price was as low as 40 $\$MW\,h_{th}^{-1}$ with an average price of 115 $\$MW\,h_{th}^{-1}$ [33]. Also, in Denmark, district heating plants based on high fractions of solar thermal are able to produce at values ranging from 57 $\$MW\,h_{th}^{-1}$ to 113 $\$MW\,h_{th}^{-1}$ (in 2007) [34]. Although a comparison is made between production cost and retail price, these figures suggest that heating by means of excess electricity driven HPDH is in the same price range as other current technologies.

The amount of excess electricity used in the simulations comes from a previous economic analysis of almost 100% renewable scenario in PJM Interconnection (Budischak et al.) [7]. This model outputs a similar amount of excess electricity, being the ratio excess to sold electricity of 106%. In the Budischak cost optimization, no value was assigned to excess electricity. This study shows that it is possible to assign a range of prices to the excess electricity and still obtain heating production costs comparable to that of traditional fuel systems. Thus, our most broad finding is that integration of the electric power system with the heating system makes high renewable penetration scenarios more economically competitive.

These results can be achieved with realistic values of the installed HP and TES units. Scenario NG16-EL10-HP – which gives the largest installation sizes for the given electricity price – is at least cost with 55 GW_{el} of HP units and 4.3 TW h_{th} of TES. If compared to the number of citizens served (about 50 million), on average 1.1 kW_{el} of HP and 1.2 m^3 of TES[7] are needed. If three people are assumed to live in a dwelling, these values become 3.3 kW_{el} for the HP and 3.7 m^3 for the TES in each dwelling. The value for the heat pump is in line with traditional household installations, where typically a heat pump of 5 kW_{el} can serve a 100 m^2 dwelling (coupled with NG backup for the coldest days). The optimum size of the TES results in higher values compared to traditional household units which are generally less than 500 liters per household (these water tanks are mostly sized for providing DHW only). However, district heating plants are subject to less stringent constraints on the available space, and volumes occupied by TES can be much larger. As an example, Marstal district heating plant serves about 1500 dwellings and has 80,000 m^3 of pit thermal storage installed [35], which makes an average of 53 m^3 per dwelling. The total optimum TES calculated in this study can be obtained by a mix of large water tanks and seasonal storage. Large tanks up to 10,000 m^3 are generally located above the ground level and can occupy the volume of a building. On the other hand, hot water tanks are modular and flexible to distribute over larger areas. Conversely, seasonal storage requires very

[7] The conversion assumes that 1 m^3 of water can hold 70 kW h_{th} of thermal energy by exploiting a temperature difference between its maximum and minimum energy level of 60 °C. This temperature difference is achievable with high temperature heat pumps as shown in Table 3.

large volumes (the feasibility is limited to certain areas) that are generally located underground to minimize the use of land surface.

A further implication of this study relates to the possibility of a significant reduction in CO_2 emissions. In NG8-EL10-HP, the model reaches an optimum where 83% of the heat demand is supplied by renewable energy. This optimum value can be higher than 95% with higher cost of natural gas, while still remaining competitive with other technologies. It was found that thermal storage plays a key role in reducing natural gas consumption (and as a consequence CO_2 emissions). As an example, in scenario NG8-EL10-HP introducing 2.1 TW h_{th} of storage not only slightly reduces the heating cost but also halves the NG consumption. Thus, thermal energy storage turns out to be a low cost tool for further reducing CO_2 emissions.

Although the scope of this study was limited to the concept shown in Figs. 1 and 2, other concepts could had been investigated for providing the heating demand by means of excess electricity. Among the more interesting alternatives, a future investigation on the following could lead to competitive production costs.

Direct resistive heating without HTS allows for very cheap installation and maintenance costs. However, the drawbacks of resistive heating described in Section 1 still apply. Especially, resistive heating requires more excess electricity than heat pumps and in many cases it was found to be not sufficient to cover all the heating demand, as shown in Figs. 4 and 5. Results show that natural gas would cover above 40% of the required thermal load (Table 9) compared to NG coverage as low as 3% achievable with HPDH. Another drawback of this approach is the absence of thermal storage that can accommodate heat from excess electricity when it is higher than the thermal load allowing for a higher exploitation of excess energy and smaller heating equipment size.

Another alternative concept could be to install centralized NGB in the power plant instead of on site. The advantage of such system is a potential lower installation cost of the boiler unit, as larger NGBs are about 50% cheaper than household units (see Table 6). Furthermore, centralized NGBs could be used to charge the TES at lower rates over longer timescales instead of being exploited only for backup in short high power bursts. This would result in smaller design sizes and reduce investment costs. The drawbacks are to be found in distribution losses of the thermal power coming from NG which, in high NG price scenarios, could have a significant impact on the heat production cost. Also, this concept does not allow for any CO_2 reduction.

This study is based on the assumption that the heating demand is at 1999–2002 levels. However, low energy buildings, including some passively-heated houses, will become more frequent for new construction in many countries. Retrofitting new buildings and the integration of renewables (such as thermal solar) can also lead to a significant reduction in energy consumption for the residential and commercial sector. These practices, if aggressively pursued can technically lead to a 36% reduction of energy consumption in the residential and commercial sectors by 2030 in the US [36]. However, the building stock in the US is foreseen to increase in the next decades and for a business-as-usual scenario in 2030 the energy consumption is assumed to increase by 28% [36]. Thus, with some factors leading to higher thermal load and others leading to lower thermal load, the use of excess renewable energy for heating is expected to be of value regardless of such changes, as analyzed here, could reduce CO_2 emissions.

7. Conclusions

Several prior studies assess the technical and economic feasibility of covering electricity demand on large scales by means of renewable resources and electricity storage [4–8], with one common result being that for cost-optimized electric systems, it is more efficient to sometimes generate excess electricity than to purchase more electric storage. This analysis models alternative ways to use that otherwise wasted excess electricity, specifically, by electric heating in conjunction with low cost thermal energy storage. Adding *electricity-to-heat-to heat storage-to-heat load* gives operational flexibility beyond traditional electricity-only systems. While some authors already suggested this approach [7], its feasibility was only suggested based on overly-aggregated time for calculations. Here, a more in depth investigation was made using hourly resolution, finding that high renewables systems benefit from selling excess power for heating purposes. Thus, extra revenues for the renewable generation, lower costs for customers, and higher attractiveness of high-penetration renewable technologies. More generally, this insight on designing future heating systems makes more possible a low-CO_2 and sustainable future. Diversification of energy sources, self-sufficiency of national energy systems, better handling of renewable power generation fluctuations and affordable energy price are all topics linked to this study that most recent works point out to be fundamental for developing future sustainable solutions [37–39].

Expanding on [5] and [7], the use of excess electricity for residential and commercial space heating and domestic hot water production in the North-Eastern part of the United States was modeled. Two types of heating systems were evaluated, based on the least-cost system for providing building thermal loads. The first system was a heat pump, district heating network, with thermal storage at the district level, and natural gas fired boiler back-ups installed on each building site. The second system used high temperature thermal storage and electric resistance heaters in each building. The excess power time series is a result from a previous study that simulates a scenario with 95% penetration of renewable energy [7]. The heating load was calculated based on ambient temperatures, natural gas consumption, and domestic hot water production patterns. Four years of hourly functioning heat load (from 1999 to 2002) were simulated for a range of excess electricity and NG prices. For each combination of the two price parameters, the optimum size for the heat pump and the thermal storage, as well as the minimum heat production cost, were calculated.

Results show that heat production costs at levels lower or similar to the current most competitive ones are achievable even when there is a charge for the excess electricity. This finding also enhances the competitiveness of high renewable penetration scenarios, where in prior studies excess electricity is often assumed to be spilled, and not producing revenue. The present model thus has provided a more convincing validation of the claim made in [7] about use of excess electricity for heat.

It was found that for all but one price combination, centralized district heating based on heat pumps and large storage units were lower cost. The exception was one case of high gas cost and zero price for excess electricity, in which case resistance heating and high temperature storage was more cost-effective. Generally, if centralized heat storage is available, the heat pump system seems more cost-effective than the resistance heating. In specific national or regional contexts, and in some buildings, other factors will determine which type of heating and storage will be used. These other factors affecting system choice would include local building policies, size of existing heating system, availability of district heating right-of-way, first-cost constraints, and others. A mix of these two heating system types within an area is also possible.

Environmentally, a significant (up to 97%) reduction in CO_2 emissions from residential and commercial heating can be achieved in most scenarios, especially by installing thermal storage.

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