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Decarbonising the EU heating sector

Integration of the power and heating sector

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Foreword

This report addresses two very timely issues that are of high policy relevance. It tackles elements of the just released EU climate communication and the heating and cooling strategy. First, it examines the heating sector focusing on the built environment — responsible for 40% of the final energy consumption in Europe. Then, it describes possible decarbonisation pathways. Second, it analyses the interactions between the heating and power sectors identifying solutions that can provide benefits to both. The challenges and implications of the coupling of these sectors are addressed and quantified.

This thorough analysis relied on large amounts of data — most of them publicly available — and open source modelling tools, developed by the JRC or existing in the public domain. It is the first public study that uses a fully open European-wide state of the art unit commitment and economic dispatch model, which incorporates features tailored to link the power and heating sectors.

The aim is to provide a deeper understanding of the effect of the power and heating sectors coupling at European level. Results and conclusions can contribute to shape and support the implementation of the Heating and Cooling Strategy, the Clean Energy Package and the EU strategic long-term vision for a prosperous, modern, competitive and climate neutral economy.

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Abstract

The heating and cooling sector has been recognised, by the EC, as a priority to achieve the decarbonisation and energy efficiency targets. Heating and cooling in the built environment accounts for almost 40% of the total final energy demand in Europe. Heating as a predominant end use has strong interconnections with many energy sectors and carriers. Thus, this report focuses on the integration of the heat and power sectors and how an effective integration can contribute to the energy efficiency and the climate change mitigation targets.

The first part of the study presents the heating sector in the built environment describing a detailed energy break down, and related costs, emissions and efficiencies. Then, the concept of system integration of heating and power is examined presenting its merits and challenges.

The second part of the study focuses on the assessment of two clean transitions pathways of the heating sector, namely electrification of heat and efficient heat and power production and district heating network. Both of them are examined from the power system perspective based on a detailed model of the European power system.

Summary

Policy context

The EU strategic long-term vision for a prosperous, modern, competitive and climate neutral economy by 2050, stresses once more the importance of an integrated energy system approach in order to achieve deep emissions reductions. Before that, EU Heating and Cooling Strategy highlighted the synergies in the energy system where district heating and cooling, cogeneration and smart buildings are expected to play a major role. In the Strategy, the need of an integrated approach within the energy system is also mentioned, which makes the power and heating sector coupling a key issue.

This study will attempt to cover the knowledge gap of these policy documents, addressing the lack of official statistics of the heat sector and the limited understanding of the interactions among the different sectors when analysing individual decarbonisation strategies.

Main findings and conclusions

Two main energy transitions pathways of the heating sector were examined from the power system perspective, namely electrification of heat and efficient heat and power production and district heating networks. The following conclusions are drawn:

— Electrification of heat

- Current heat electrification rates vary from 3% to 32%. Member States with an electrification rate below 5% are Denmark, Hungary, Lithuania and Romania. Member States with electrification rates above 20% are Finland Portugal and Sweden.
- If all current fossil-fuelled heat generation technologies were replaced by heat pumps overnight the combined emissions of the heat and power sector would be reduced by 16%. The exact percentage per Member State varies based on the current and projected composition of the power and heat sector. The biggest potential is found in FR with a 65% and the lowest potential in PL and EE with 4%. Without additional "clean" capacity additions the additional electricity demand for heating will be mainly generated by dispatchable sources which usually have higher emission rate than the average electricity generation mix. In a future decarbonized power system context the combined heat and power emissions would be reduced by 25% even without considering additional clean capacity.
- Based on the above scenario, heat pumps demand would be 26% of the total electricity demand adding 526 TWh to the final electricity consumption (2910 TWh). This demand would be unequally distributed between summer and winter season. The increase in the winter peak demand is expected to be 20% to 70% higher than today with an average of 41%. The biggest changes in absolute terms would be noticed in Germany (+108 GW), France (+26 GW) and Poland (+ 47GW).
- Firm power capacity of the current power system starts to become inadequate for electrification rates above 32% (replacing around 60% of fossil fuelled heat). Beyond that point, the role of flexibility measures will become more relevant. For the extreme future scenario, it would result into an average loss of load of around 2%, while some countries show lost load values of up to 7%.
- In this case, the energy not served can be reduced with a more flexible demand. By shifting just 6% of the monthly peaks to off-peak time, the unserved energy is reduced by half.
- In the base scenario of the future power system scenario we observed a lot of curtailed renewable energy. In a fully electrified scenario, curtailed energy is reduced by 17% as electricity as this electricity is used to satisfy heating needs.

— Centralised cogeneration and District heating

- The current power plant fleet has the theoretical potential to satisfy 58% of the European space heating demand. The utilization of this CHP capacity results in a substantial cost reduction of the total energy system — 17% and 20% for the current and future scenarios respectively.
- If all current or future steam based power plants were operating into CHP mode together with district heating networks (including thermal storage), the overall efficiency of the energy system would increase significantly. In the current scenario, the efficiency raises from 63% to 76%, while in the future scenario (2050) it raises from 73% to 80%.

- The expected increase of the energy efficiency in the built environment will allow for a larger share of heat supplied from centralised cogeneration. As a result, in the future scenario, the share of heat that can be covered from CHP reaches 70%. In other words, the ratio of the heating demand in the built environment to the available CHP capacity decreases over time.
- If the thermal power plants are operating in cogeneration mode, there is a notable increase in curtailment of renewable energy. It is estimated that this will fall in the range of 1 – 9% for the current scenario and 6 – 10% for the future one. Enhancing the interconnections or storage capacity could alleviate this effect.

1 Introduction

The heating and cooling sector has been recognised as a priority to achieve decarbonisation targets set for the European energy sector. It accounts for almost half of the EU energy consumption. Consumption for heating and cooling is dominant in three main sectors, namely residential, tertiary and industry, with the residential (mainly households buildings) representing the highest share. The residential sector accounted for 45% of final heating and cooling energy consumption in 2012, followed by industry's share (37%) and services (18%) (Ragwitz et al. 2016). In general, the heating and cooling sector is characterised by low efficiencies, large amounts of waste heat and it is mostly fossil based (European Commission 2016a).

Currently, heat and power is not fully integrated. The energy system relies mostly on technologies that convert a specific input fuel — gas, liquid or solid fuels, electricity — into heat while the power needs are supplied by centralised power plants, including centralised renewable power plants, or decentralised solar and wind power plants. To achieve deep emission reductions in the European energy system and in the heating sector in particular, synergies and interactions among the different energy carriers and energy uses are encouraged. This trend is sometimes mentioned by different terms such as "sector integration", "sector coupling" and an "integrated system approach" is usually reccommended to study its effects. In other words, a future sustainable energy system will benefit from a stronger integration of electricity, gas, heating/cooling, mobility systems and markets to maximize the synergies among new technical solutions, (European Commission 2018).

The shift towards the future energy system, based on the multi-sectorial coupling, implies the deployment of technologies that are able to convert between energy carriers and energy storage systems. Key technologies in this shift will be, among others the following: combined heat and power, power to gas, power to heat, power to liquid and electric and thermal storage. Such an integrated approach will not only contribute to the decarbonisation but can also facilitate new innovative energy business models that can foster competitiveness in the energy sector.

This new paradigm can leverage the energy system benefits and alleviate its drawbacks. For the heat and power coupling, some features that make this integration favourable are: the highly-efficient combined heat and power production, the cost-effectiveness of thermal energy storage compared to electric energy storage, and flexible power to heat technologies. These features will allow the incorporation of larger amount of renewable energy and guarantee the energy supply at affordable prices. Furthermore, within the heating and cooling sector lies great potential for reducing its carbon intensity by switching to electricity as an energy carrier.

This study focuses on the decarbonisation of the heating sector in the built environment of the residential and teriary sector via different sector coupling pathways. It presents, in detail, the heating sector including energy breakdowns by uses and fuel shares, costs, efficiencies, emissions and its link to the power system. Then, it assesses the benefits that the coupling between heating and power sectors can bring into the European energy system, focusing on the built environment and its impact on the power system. Specifically, the following two alternative pathways are examined, covering both the demand and supply sides. The first one is the electrification of the heat demand where the focus falls on the demand side using electricity as energy carrier. The second refers to the utilisation of excess heat of thermal power plants via cogeneration and district heating networks. A third possible pathway would be based on the use of a renewable and low carbon gas as main energy carrier. This gas could be transported, stored and distributed by the existing gas infrastructure, offering flexibility to the grid and using the current gas infrastructure. In this report we do not further examine this option as it requires a more systemic approach and further considerations of the gas sector but it merits to be highlighted as a possible decarbonisation solution of the heat sector.

2 The European heating sector

This section describes the European heating demand of the tertiary and residential sectors, which represent the entire built environment. The analysis covers the heating and cooling needs for different uses (e.g. space heating and cooling or domestic hot water). On top of that, the electricity for heating uses is analysed further from the power system point of view. The analysis is done both on annual and hourly levels.

2.1 Heating in the EU building sector

The heating and cooling sector represents half of the energy consumption in the EU, being supplied 75% by fossil fuels (European Commission 2016a). Buildings, including residential and services sectors, currently account for 40% of the total final energy consumption in the EU – having the largest share (European Commission 2018). The residential, alone, is responsible for 54% of heating and cooling consumption, followed by services - 21% and industry - 24% (final energy - 2015 data) (Figure 1.). Therefore, the heat supply to the built environment and industry has been identified as a key pillar in the European energy policy to achieve a climate neutral Europe by 2050. The following sections focus on the role of buildings in the heating sector.

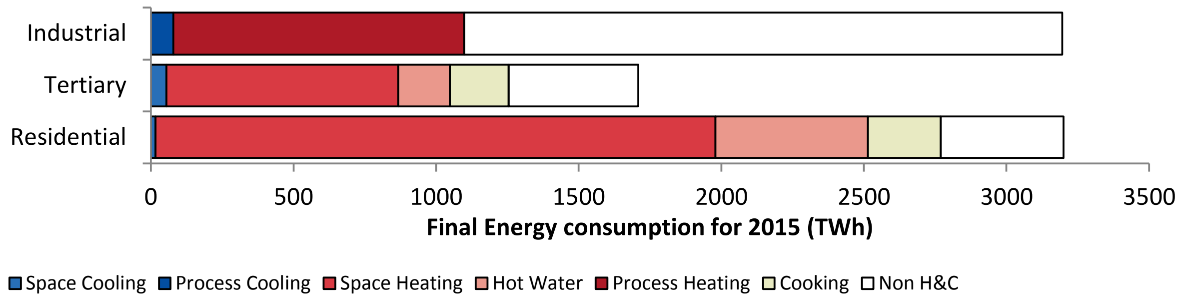

Figure 1. Shares of final energy demand per end-uses and Member States

Due to the long lifetime of buildings, 80% of today's building stock would still remain in 2050. As a result, the renovation activity in the building sector is expected to be the dominating one, among demolition and new construction (Artola, I., Rademaekers, K., Williams, R., & Yearwood 2016) in order to decarbonise the building sector and reach GHG reduction targets. Improved building insulation, smart appliances or energy management systems could contribute to moderate the energy requirements. Still, all these measures should be followed by a fuel shift that enables the utilisation of cleaner energy sources to meet the remaining energy needs. These sources cover, among others, renewable heating — including electricity — and district heating fed by renewable sources — including renewable gas or solar thermal.

Heat for residential and tertiary sectors accounts for about 35% of the total demand in the EU since 2000 — 20 times larger on average than the final cooling demand during the same period. At national level, it represents the largest share of the final energy demand. This also applies to Southern European countries despite the fact that they are characterised by warm climate conditions.

Heating and cooling demand are usually studied together and are directly related to temperature. As observed in Figure 2, cooling is a very small fraction compared to heating. The fact that the heat demand is so much higher than the cooling demand can be explained by the temperature profiles and the implied comfort zones (Figure 2). Most of the year, temperatures are moving into the heating zone (for most Member States) while cooling is only limited to a few hours per day during the summer months. This is the reason why such studies, including this, focus on heat demand.

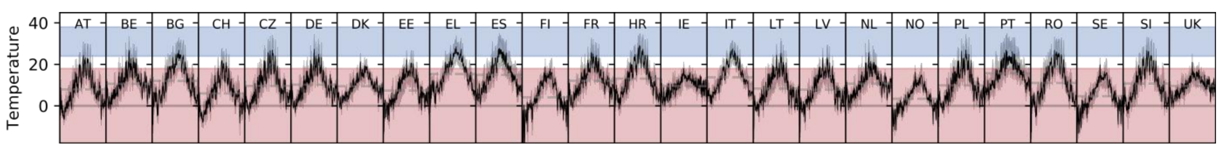

Figure 2. Daily temperature evolution per EU country for 2016. The grey bands above and below the main line correspond to the minimum/maximum temperature of the day. The temperature region in which space heating and cooling are marked with red and blue respectively

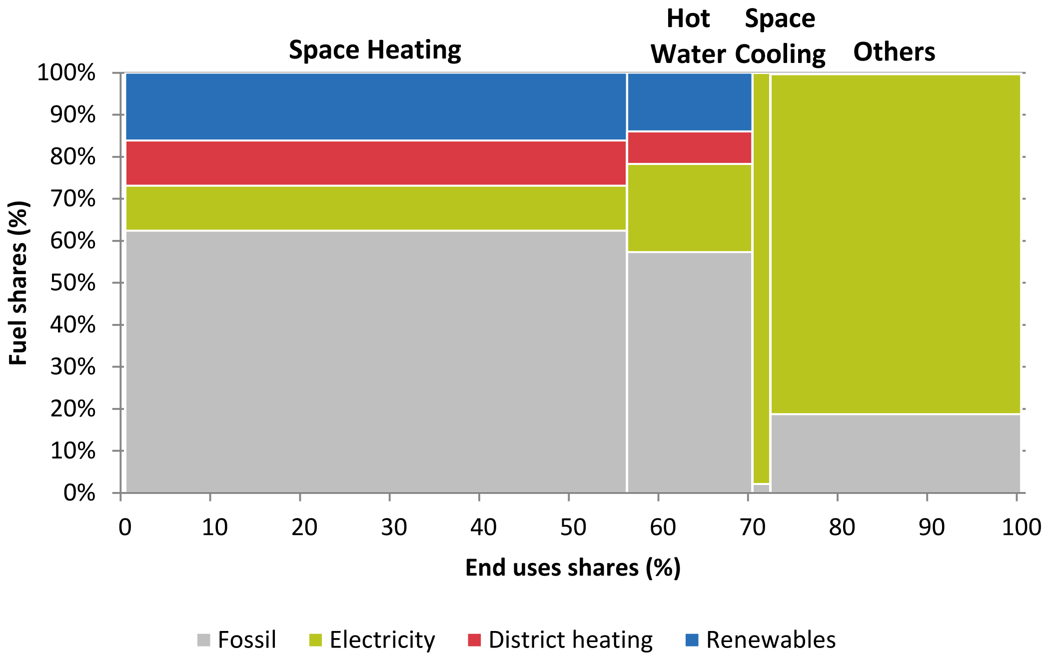

Figure 3. A comprehensive view of useful energy composition of the built environment for different end uses and fuels in the EU

Heat demand includes three major uses: hot water, process heating and space heating. The latter accounts for more than 50% of the heat demand while heat for hot water (DHW) purposes represents 15% (Figure 3.).

Fossil fuels still represent the highest share of the fuel mix in the European heating sector for the residential and tertiary sector (62% and 57% for the space heating and DHW uses respectively). The remaining share, around 40%, relies on low carbon technologies – such as district and electric heating, as well as renewable fuels, namely biomass.

At country level, large differences are observed. Figure 4 presents the space heating needs in 2015 as well as their fuel breakdown at country level. Two northern European countries boast with the highest shares for cleaner heating technologies: Sweden gets almost 95% of the space heat in buildings from district heating networks, electricity and renewables, while Finland claims the second place with roughly 90%.

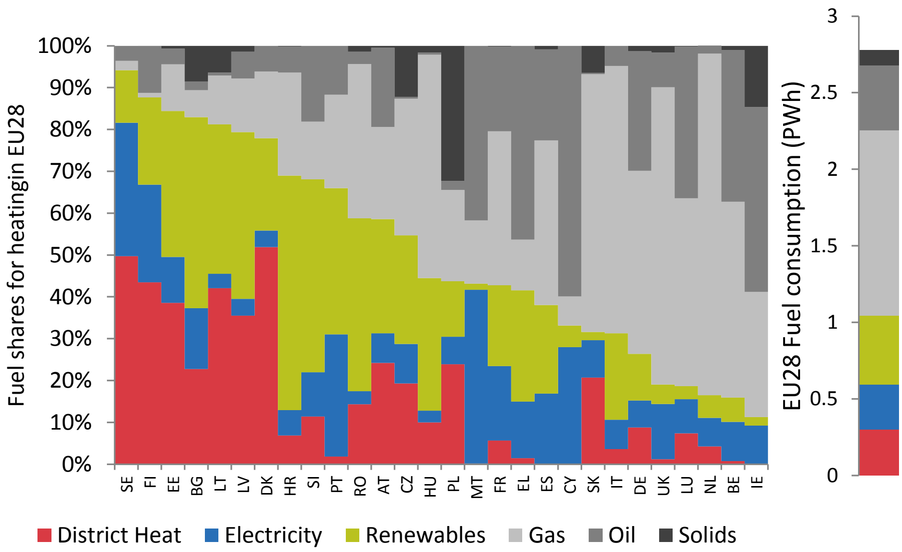

Figure 4. Fuel consumption for space heating in 2015. Member states are sorted by the amount of fossil fuels they are consuming

Correspondingly, trends based on geographic locations are observed: district heating is particularly dominant in northern European member states, while renewables – due to large biomass shares– are leading in Eastern Europe. Consequentially, the Baltic countries combine both characteristics and exhibit a share of around 80% of low carbon heating fuels. The heat supply in central and western countries is largely based on gas. Oil still plays a large role in a number of member states, while coal for residential heating services is primarily relevant in Poland.

The evolution and projection of the final energy consumption for heating and cooling services in buildings is presented in Figure 5. The historical data are based on JRC IDEES database (Mantzos et al. 2017). The baseline evolution of heat demand per country if there are no decarbonization policies in place is taken by (Nijs, Castelló, and González 2017). In order to ensure the consistency of the dataset we use the relative difference of the latter among different years and fuels and we apply it to the historical data of IDEES..

Historically, not big changes are observed in the heating sector. Minor deviations on the total demand are caused by variations in the weather, which has a large impact on the built environment energy needs. As a result, the colder the weather in a year the higher the heat demand. By 2050, building renovations and other energy efficiency measures are expected to reduce the final energy consumption in the residential and tertiary sector by over 25%. Coal, oil and gas consumption for heating is massively reduced. The use of gas and biomass decreases, while district heating and electricity shares increase.

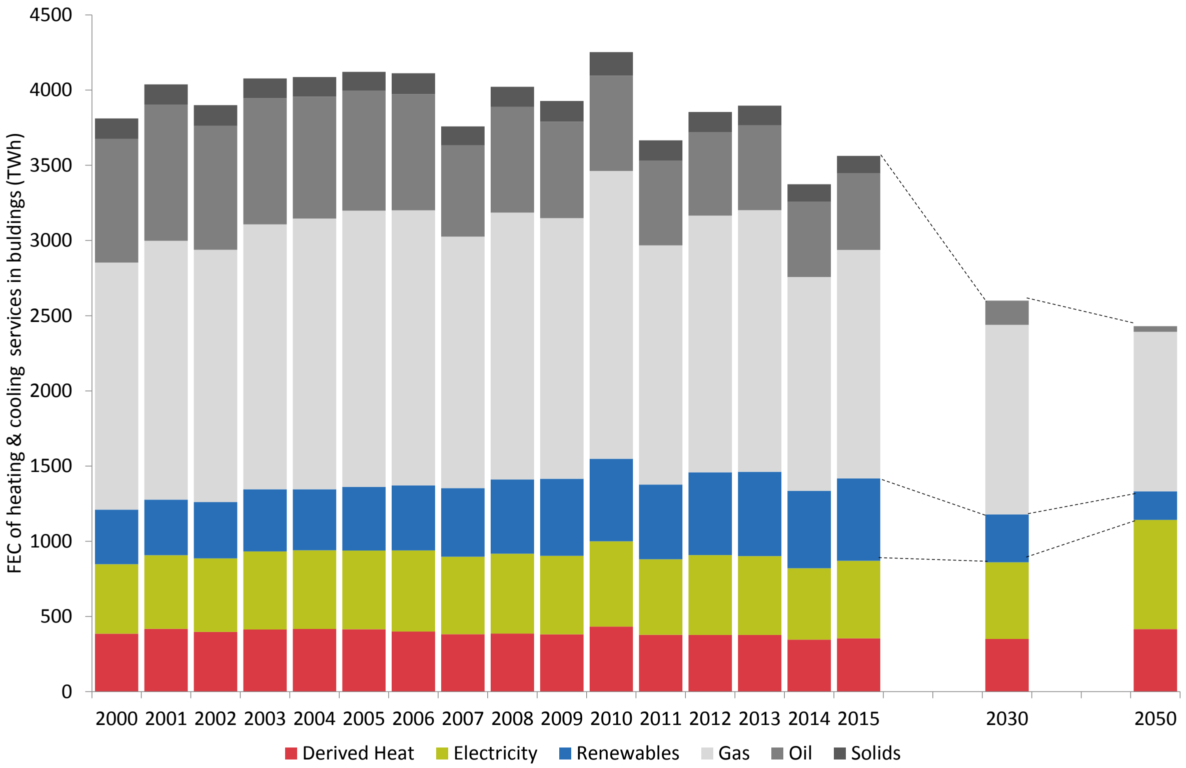

Figure 5. Historical development and projections of fuel consumption for heating

Accounting framework

In order to be able to provide a fair comparison we need to account the benefits and drawbacks of both heat and power sectors covering the same end use.

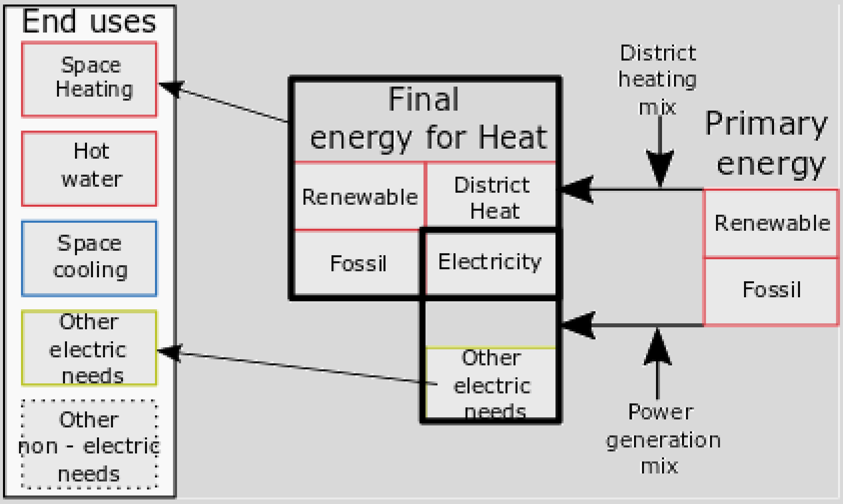

Figure 6. Energy accounting framework for assessing heating and power energy breakdown costs, efficiencies and emissions

2.1.1 Efficiencies

The overall national heat supply efficiency — defined as the ratio between the delivered useful heating energy to the final energy consumption — remains low. Due to the existence of high-efficient technology solutions, such as heat pumps, combined heat and power or even condensing boilers, higher values may be expected. However, the persistence of old energy generation equipment impedes higher efficiencies. As a result, the heating sector offers significant opportunities to decarbonise the energy sector.

At national level, countries with the lowest shares of fossil fuels present higher overall efficiencies in the heating sector. This is the case of Sweden and Finland that show efficiencies values above 90%. In these countries, a large share of the heat demand is supplied via district heating, electricity or renewables. These options offer higher efficiencies in comparison with fossil-fuelled technologies (Figure 7).

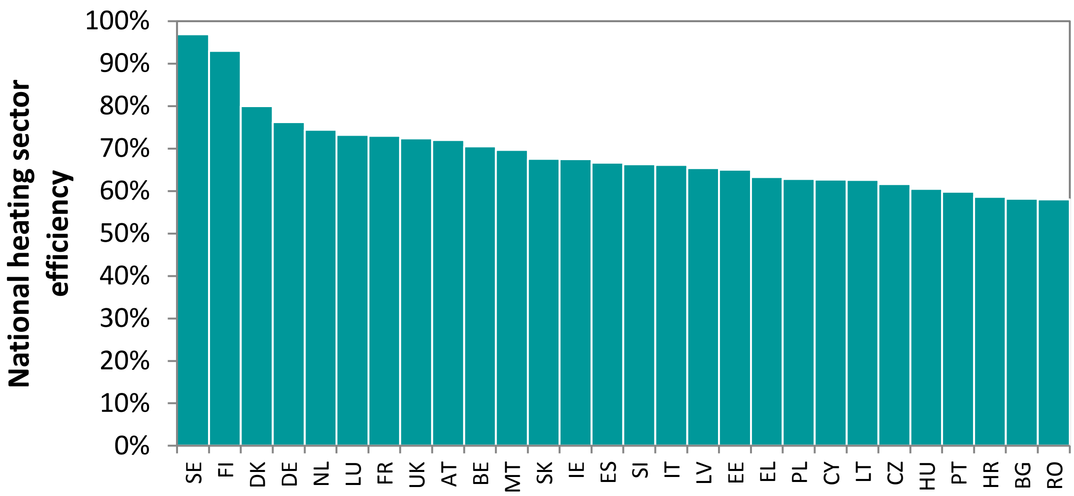

Figure 7. Overall national heating supply efficiencies

2.1.2 Costs

Similarly to the case of national heating efficiencies, national unitary heat costs vary across Europe. Heating costs depend on national energy markets rules, including taxes and tariffs, but also on the national energy mix**.** Figure 8 shows the national unitary heat cost computed as the weighted average of the unitary costs of the different energy fuels — gas, oil, solids, electricity, renewables and derived heat — and their contribution to the final energy consumption per country based on Eurostat energy mix (Eurostat 2018)[1]. Heat prices range from 127 EUR/MWh in Malta to 43 EUR/MWh in Romania. The European average value is 70 EUR/MWh (Figure 8).

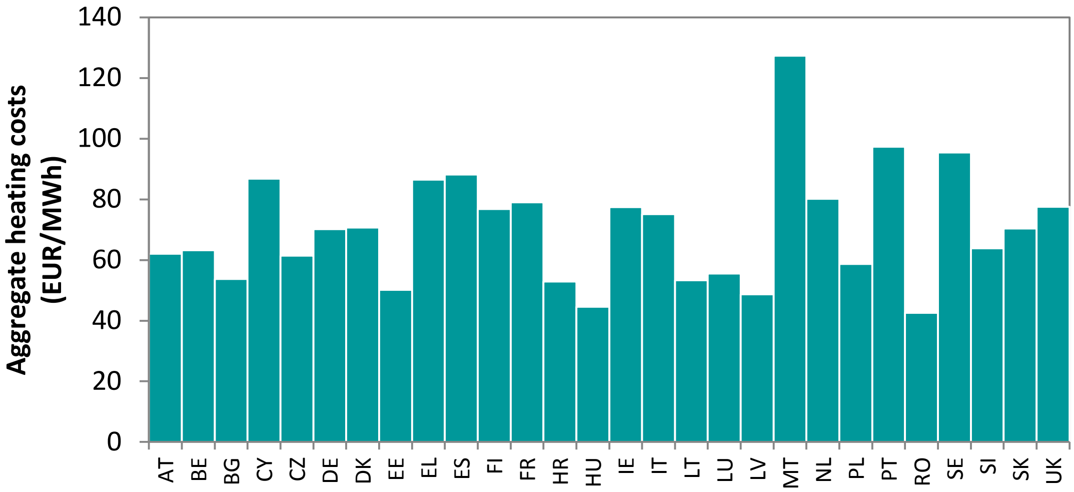

Figure 8. National unitary heat cost

The heat costs provided from district heating have been calculated following the same approach. The mix of inputs fossil fuels going into district heating plants have been taken into account (Eurostat district heating energy mix). Unitary district heating cost ranges from 78 EUR/MWh in the case of the Netherlands to 39 EUR/MWh for Bulgaria, being the average EU value 53 EUR/MWh (Figure 9).

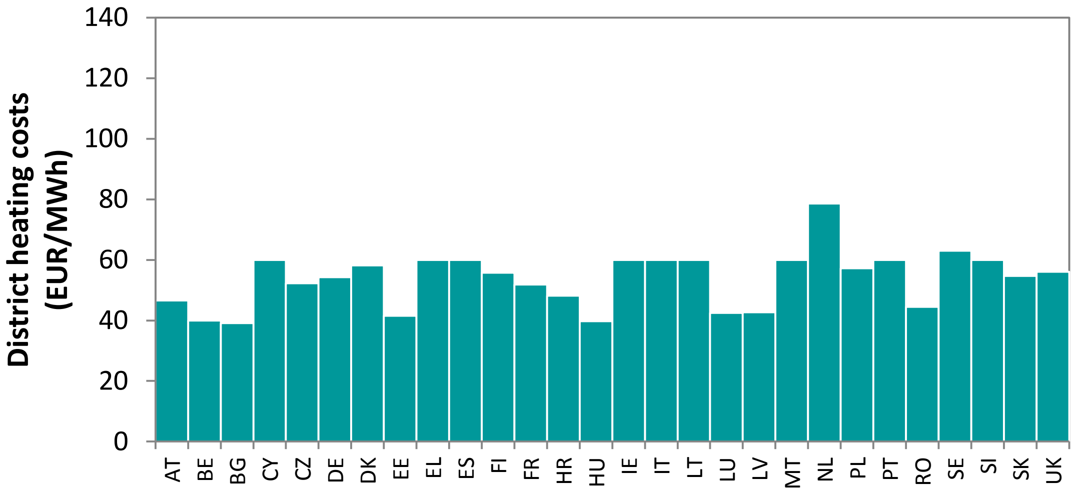

Figure 9. National unitary heat cost supplied via district heating

[1] For gas and electricity costs, we have assumed the average value of both household and non-household costs as provided by Eurostat

2.1.3 CO2 Emissions

The CO2-emission factor is essential to assess the impact of different decarbonisation pathways in the European heating sector. In this section, we present the national emission factors per unit of useful heat delivered. We calculate them following the same approach as for the efficiency and unitary costs, presented above. This means that only fossil fuels have been considered. The values presented are computed as the weighted average of the unitary emission factors and their contribution to the useful energy delivered. As result, Bulgaria shows the highest emission factor (~500 ktCO2/TWh), followed by Cyprus and Poland (487 ktCO2/TWh and 483 ktCO2/TWh respectively). On the other hand, the Netherlands shows the lowest emission factor (279 ktCO2/TWh) followed by Denmark and Germany (~300 ktCO2/TWh) (Figure 10.).

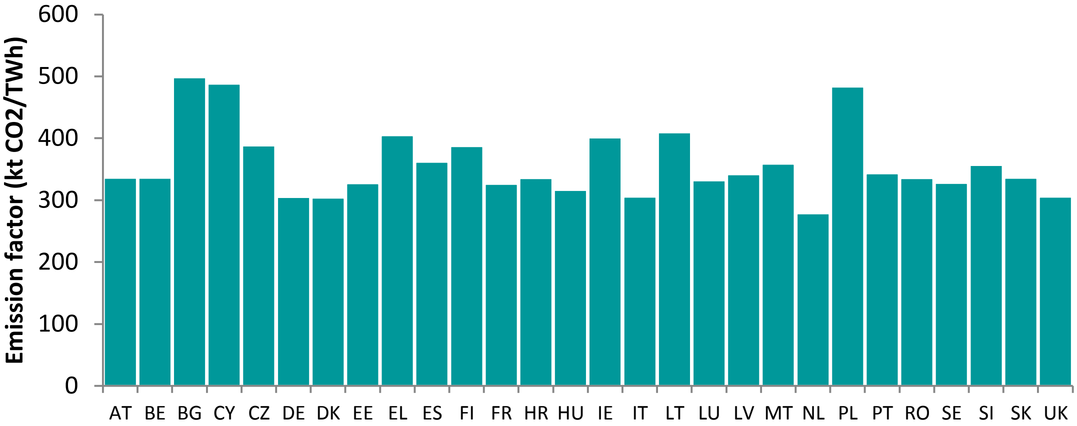

Figure 10. Emissions factors of the heating sector (space and hot water for residential and tertiary sector) in 2015 per unit of useful energy. Electricity and district heat are not accounted.

In absolute values, six countries (Germany, France, Italy, the Netherlands, Poland and United Kingdom) account for 77% of the total emissions in the heating sector, discounting the heat produced from electricity and district heat (Figure 11.). At the same time, these countries show low shares of heat from electricity and district heat. A fuel shift in them can potentially have a significant impact on the decarbonisation of the European heating sector.

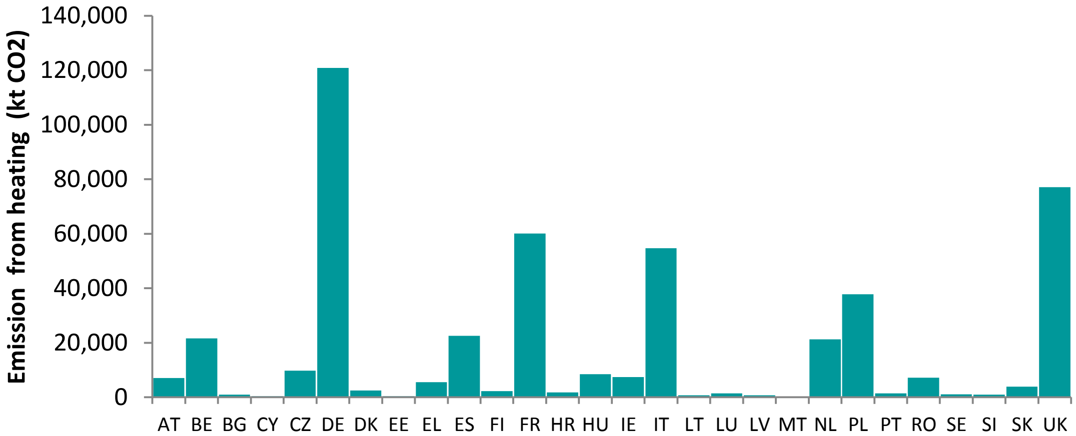

Figure 11. Total emissions from heating sector in 2015 (space and hot water for residential and tertiary sector). Electricity and district heat are not accounted. Data source: (Mantzos et al. 2017)

2.2 Electricity for heating

In 2015, electric heating and cooling services in buildings added up to 366 TWh in the EU28 — 13.4% of the final electricity consumption (Figure 12). Large shares are found in Southern European countries (Figure 13). Because of the higher average annual temperatures, countries such as Greece, Italy, Croatia, Malta and Cyprus have a high demand for air conditioning services in the summer. This leads to almost equal shares of electricity consumed for space cooling as for space heating.

Electricity consumption in 2050, according to the baseline scenario of heat roadmap Europe (Nijs et al. 2017), is rising by 830 TWh due to higher deployment of heat pumps and electric vehicles (Figure 14). This is in line with other scenarios (official or not) which place the total electricity consumption for end-uses at the range 3,400 – 3,800 TWh. According to the same scenario heat pump penetration increases strongly until 2050 and represents 6.8% of the total electricity demand. Electricity adds up to 30% of all final energy consumed for heating compared to 14.5% today. While an increased uptake of air conditioning systems will play a role in individual member states due to higher cooling demands, the effect on the European level is marginal.

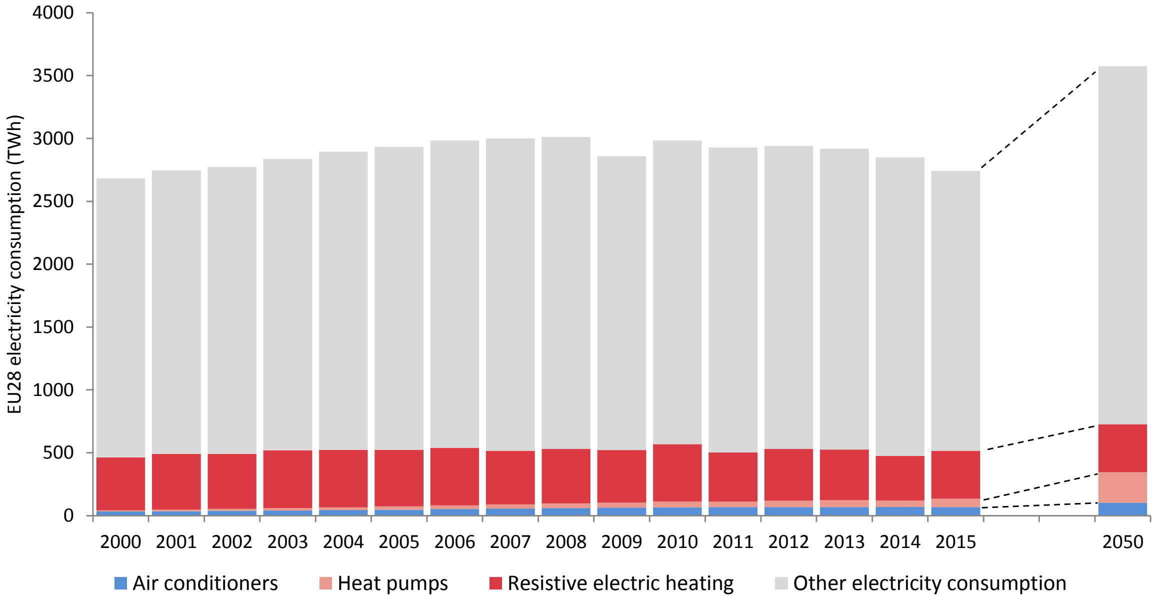

Figure 12. Scenario for the development of electricity demand under the baseline scenarios Data sources: (Mantzos et al. 2017), HRE2050 baseline scenario (Nijs et al. 2017)

Austria, Sweden and Luxembourg show the highest heat pump shares — up to 15%. Greece, Estonia, Malta and France are leading in electricity consumption related to domestic heating and cooling – with roughly 30% attributed to air conditioners, heat pumps and electric heating. In Germany, the consumption related to heat pumps rises from 5.4 TWh in 2015 to 46.2 TWh. France shows the highest total consumption, which rises to 65.4 TWh.

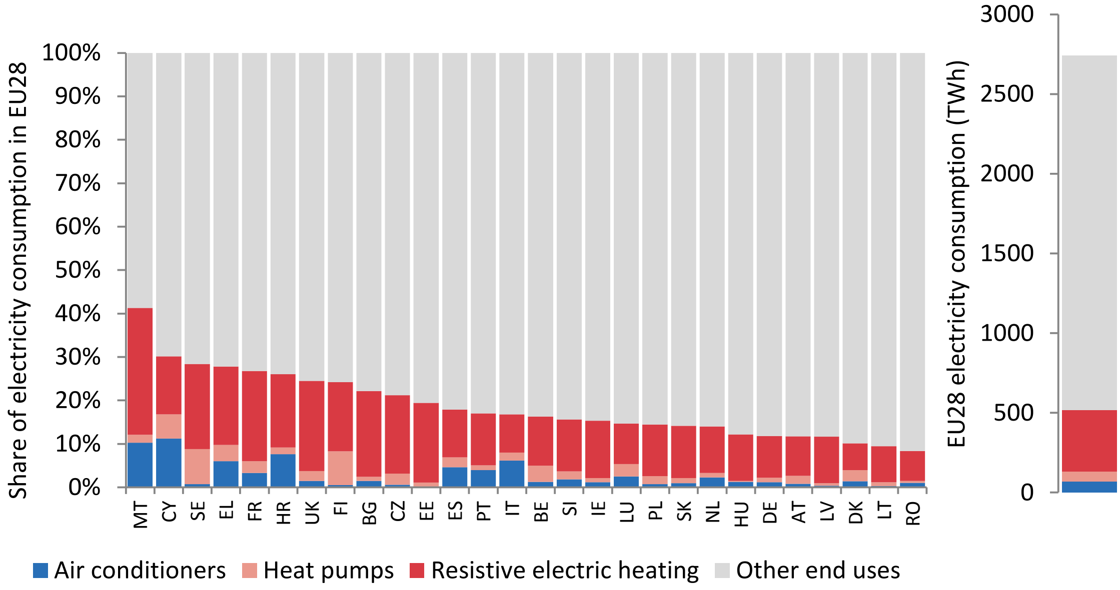

Figure 13. Heating and cooling share of electricity demand in 2015 (excluding process heat and cooling)

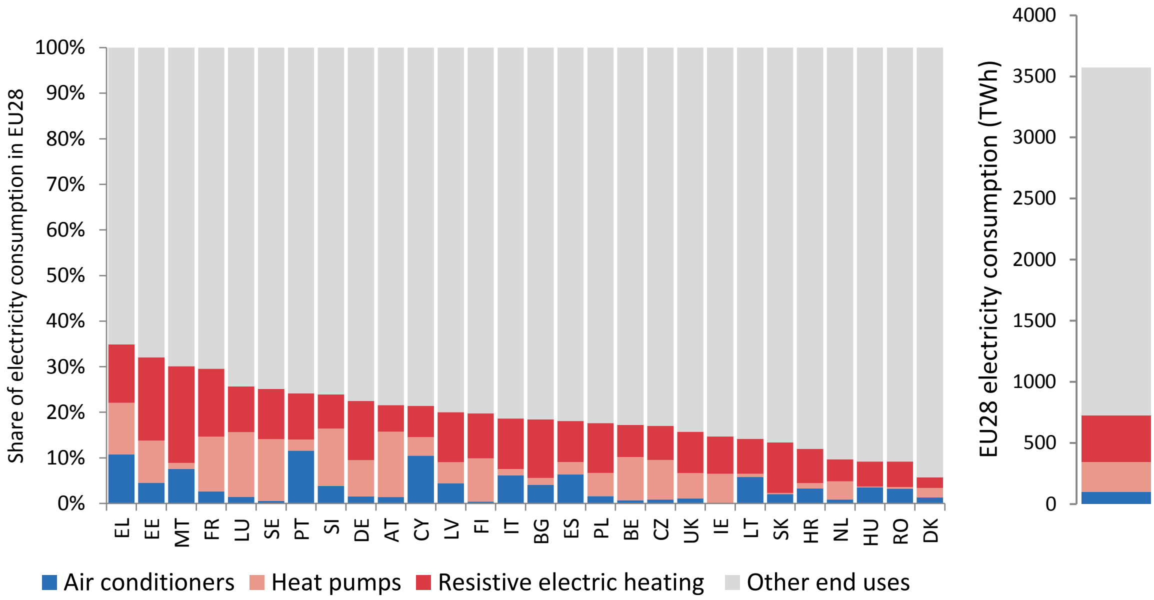

Figure 14. Heating and cooling share of electricity demand in 2050 (excluding process heat and cooling)

The demand structure changes slightly compared to 2015. Air conditioning shares increase in southern European countries and add up to significant amounts of the national electricity consumption in Greece, Croatia and Italy as well as in the island states of Cyprus and Malta, with at least 5% (Figure 14).

Heat pump shares increase significantly in Sweden and Ireland. Electricity demand from heat pumps in Sweden triples, while it increases from 0.2 TWh to 1.9 TWh in Ireland. Low heat pump shares are found in Hungary, Romania and Latvia — countries with high biomass shares and as a result less decarbonisation pressure for the heating sector.

2.3 Temporal characteristics of heat demand

We have presented annual statistics and trends for the EU heating sector. In this section we show annual time series and temporal characteristics. Later on, these time series are used in the development of the scenario analyses.

2.3.1 Heat demand profile

To generate hourly heat demand profiles, we have used the profiles developed by Victoria and Andersen (2018). These profiles have been scaled to match the national annual values for the current and future fossil heat demand as described above. The total European heat demand profiles at hourly resolution is presented in Figure 16. Annex 5 presents a comparative analysis of the different data sources and of the heat demand projections considered.

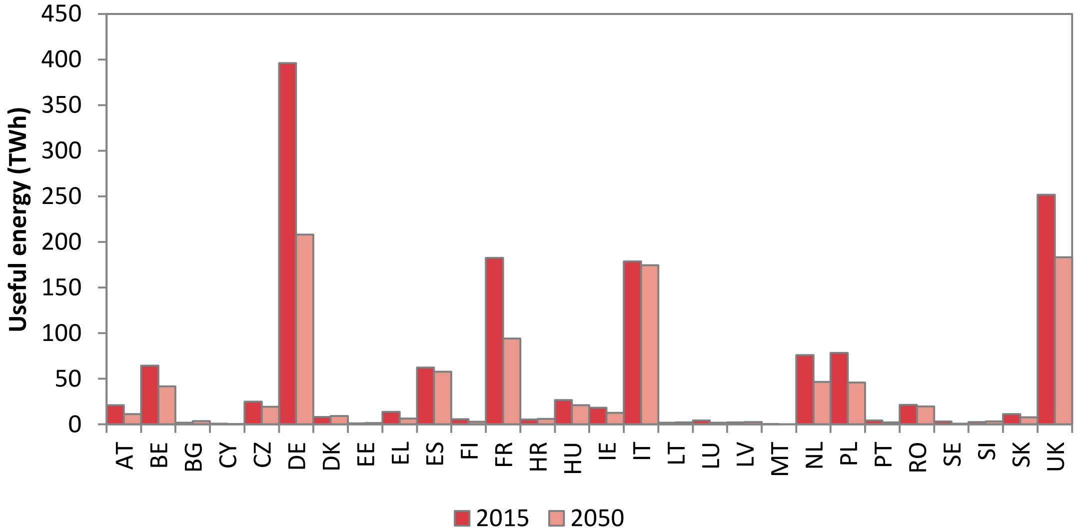

Figure 15. National fossil-based heat demand. Current and 2050 projection

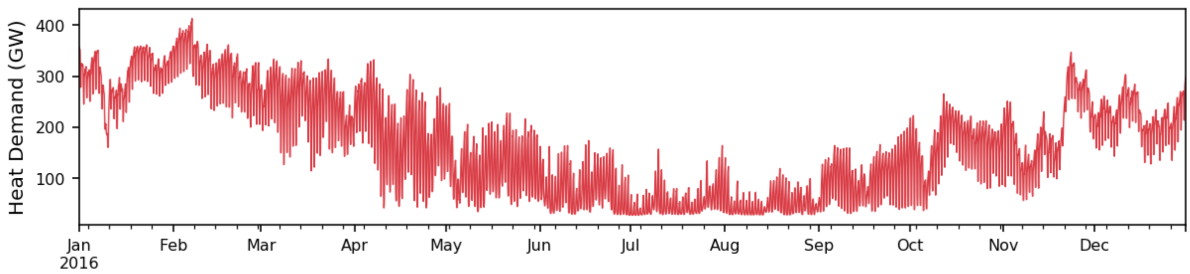

Figure 16. Hourly heat demand in Europe for 2015.

2.3.2 Power for heating and demand decomposition

As mentioned in Section 2.2, the electric-driven heating has already a significant role which may increase in the future. Breaking down this demand on the temporal dimension will allow us to examine in detail the link of the two sectors and examine future trends and scenarios.

The total power demand of a country at a national level was decomposed into three uses: electricity for space heating, electricity for space cooling and electricity of other uses. The decomposition of electricity demand to different uses is needed to analyse different heat related scenarios such as the effect of electrification of heat on the power demand curves. The following sources were used for this analysis:

— Electricity demand data from ENTSOE power portal as retrieved and pre-processed by Open Power System Data (2018)

— Weighted average Temperature based on ERA5 (Copernicus Climate Change Service (C3S) 2017) aggregated at a MS level (De Felice and Kavvadias 2019)

— Public Holidays from various public sources

— Share of electricity for space heating from JRC IDEES (Mantzos et al. 2017)

Power demand is plotted against temperature for different days of the week and hours of the day. The distribution of load in most cases is bimodal which means that the sensitivity of the electric load to the temperature during the day is different compared to night time or weekdays and weekends.

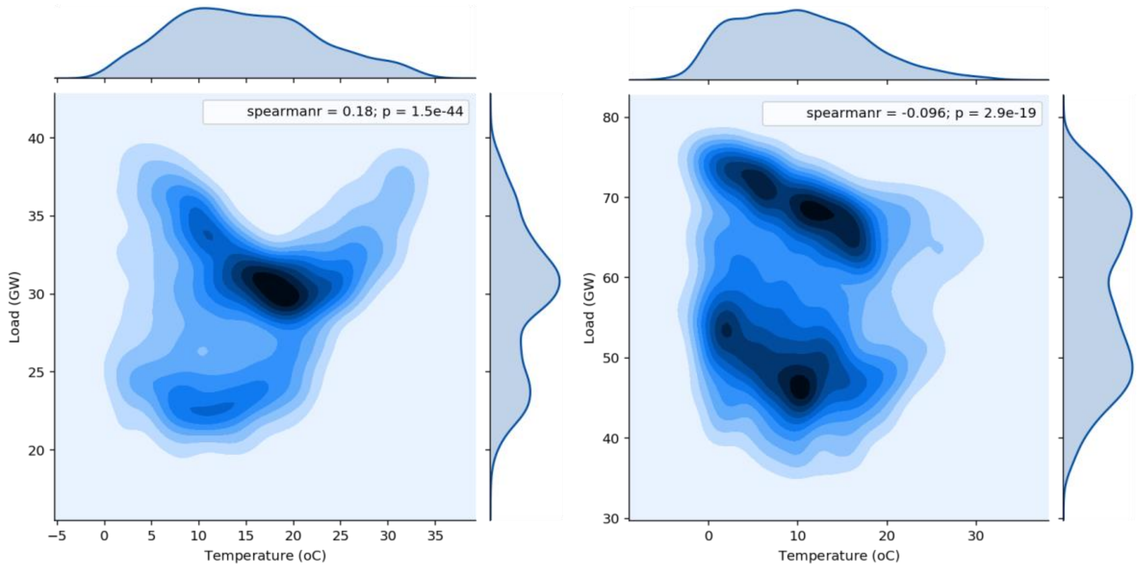

Figure 17. Density scatterplots illustrating the relationship between load and temperature for Spain (left) and Germany (right). The marginal distributions of the two variables are also shown to indicate the bimodal nature of the load (day-night, weekend-weekday).

In order to decompose the electric load into heating and cooling within a country, among different hours of the day and among weekdays and weekends and holidays we use a variable-base degree-hour method which is a generalisation of the traditional degree-day method. The following steps were followed:

1. Find hinge point base temperature for heat/cooling degree hours. This is the temperature beyond which the power demand will have a monotonic relation with the temperature. This point is found by checking the Spearman rank correlation coefficients (which show the monotonicity of a data series) for each of the base temperatures used (Azevedo, Chapman, and Muller 2015). The highest spearman factor was chosen. A very low spearman factor (below 0.2) or a high p-value (above 0.05) indicates no monotonic relationship among the variables. In that case it is safe to assume that there is no dependency of the load with the temperature. This was conducted for day and night, weekday/weekend based on the results of a density clustering.

2. Establish heat degree hours (HDH) and cooling degree hours (CDH) using the hinge points found above using the formulas:

$$CDH_t = MIN(T_t - hinge_c, 0)$$

$$HDH_t = MIN(hinge_h - T_t, 0)$$

Where T_t is the temperature at time *t* and *hinge* the identified hinge point for heating or cooling for the type of the day (weekday/weekend) and type of time period (day/night). If there is no hinge point then the CDH or HDH is zero for that time step. Exponential weighted moving average with a decay of 3 hours was applied in the resulted timeseries in order to smoothen the series and simulate the dependency of the heating/cooling load to previous timesteps. This is recommended to reduce unrealistic peaks and ramps of power demand that can be caused by fast changes in temperature and to simulate the building inertia and dependency on previous Temperature values. Finally we normalise the two time series of the above step so that their sum is 1.

3. We define the following rescaling function,

$$scale(x_t; A, B, C) = Ax_t^B + C$$

where, x_t the original normalised time series and *A,B,C* the rescaling parameters. The rescaling is done through a combination of stretching (*A*), shifting (*C*) and skewing (*B*).

4. For the decomposition the following equation needs to be satisfied:

$$L_t = Other_t + scale(CDH_t; A_c, B_c, C_c) + scale\ (HDH_t; A_h, B_h, C_h)$$

Based on this function the decomposition should satisfy the following targets:

$$\sum_t scale(CDH_t; A_c, B_c, C_c) = target\ cooling\ load$$

$$\sum_t scale(HDH_t; A_h, B_h, C_h) = target\ heating\ load$$

$$HDH_t \cdot CDH_t = 0$$

The targets are taken from real shares of electricity for heating and cooling for all historical years based on the JRC IDEES database. The last constraint assures that there is no simultaneous space heating and cooling. Since the above problem is highly non-linear and discontinuous it was formulated as a minimisation problem using a combination of positive penalty factors and solved via a genetic algorithm[2].

The decomposition was done at a Member State level. The values *A*, *B* and *C* for both the heating and cooling component result to the desired decomposed elements. In all cases the algorithm converged to the target within less than a minute. At the end the result is fully compliant with the national heating and power statistics from the above mentioned sources.

For the sake of conciseness, we present the aggregate EU demand in Figure 18. This figure includes the temperature dependent components (electricity for space cooling and space heating) and the electricity used for other purposes. Individual Curves and hinge points can be found in Annex 3.

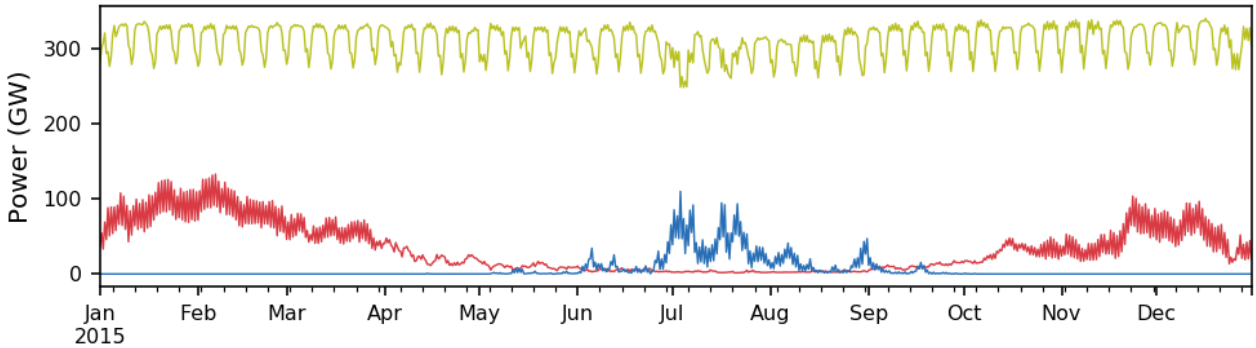

Figure 18. Aggregate electricity demand for heating (red) cooling (blue) and other purposes (green) in 2016. NB: Lines are not plotted cumulatively

[2] The python DEAP package was used

3 Heat and power sector integration

A clean power system consisting largely of variable renewable sources faces one fundamental problem: the availability of resources at all times. Intermittent energy is not always available when needed, thus causing an imbalanced residual load curve[3]. One of the ways to alleviate this imbalance, in a clean and efficient way, is through a stronger link with the heating sector. More specifically, this link can bring important benefits in the following ways:

— when the VRE generation is high and/or demand low (red part of curve in Figure 19) clean electricity can be consumed to produce heat that can be directly consumed or stored.

— when the VRE generation is low and/or demand high (green part of curve in Figure 19), electricity can be co-produced in the most efficient way via CHP or use stored electricity.

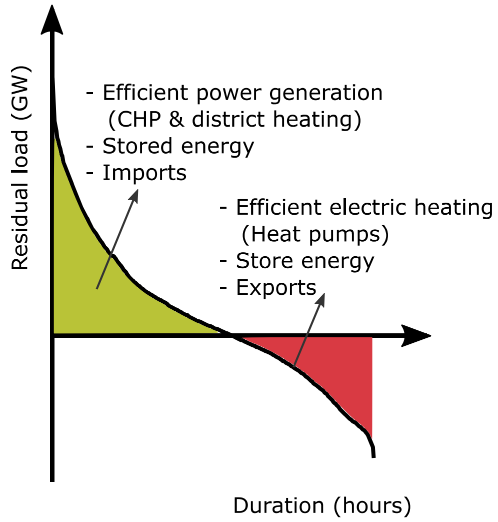

Figure 19. Ways to cover excess/deficit of electricity based on a conceptual residual load curve (demand minus demand covered by variable renewables sources, i.e. solar, wind etc.)

Based on the concepts described above, this section presents in detail the benefits and challenges that a stronger heat and power integration will bring. First, we introduce a general overview of a higly interconnected energy system. Then, the two alternative sector coupling pathways are discussed analysing both the demand and the supply side.

3.1 Towards an integrated energy system

A simplified traditional configuration of the energy sector is presented in Figure 20. It is mainly based on conventional generation that delivers the different energy needs (mostly heating and electricity) without many interactions among carriers. Both supply (national level) and demand sides (individual/decentralised) are not so much interconnected.

[3] This curve is defined as the amount of power demand needed to be satisfied minus the renewable energy at any given time step. Ordered from the highest to the lowest value, it represents the surplus of energy (right side) when VRE generation is high and demand is low, and the deficit of energy (left side) when VRE generation is low and demand is high

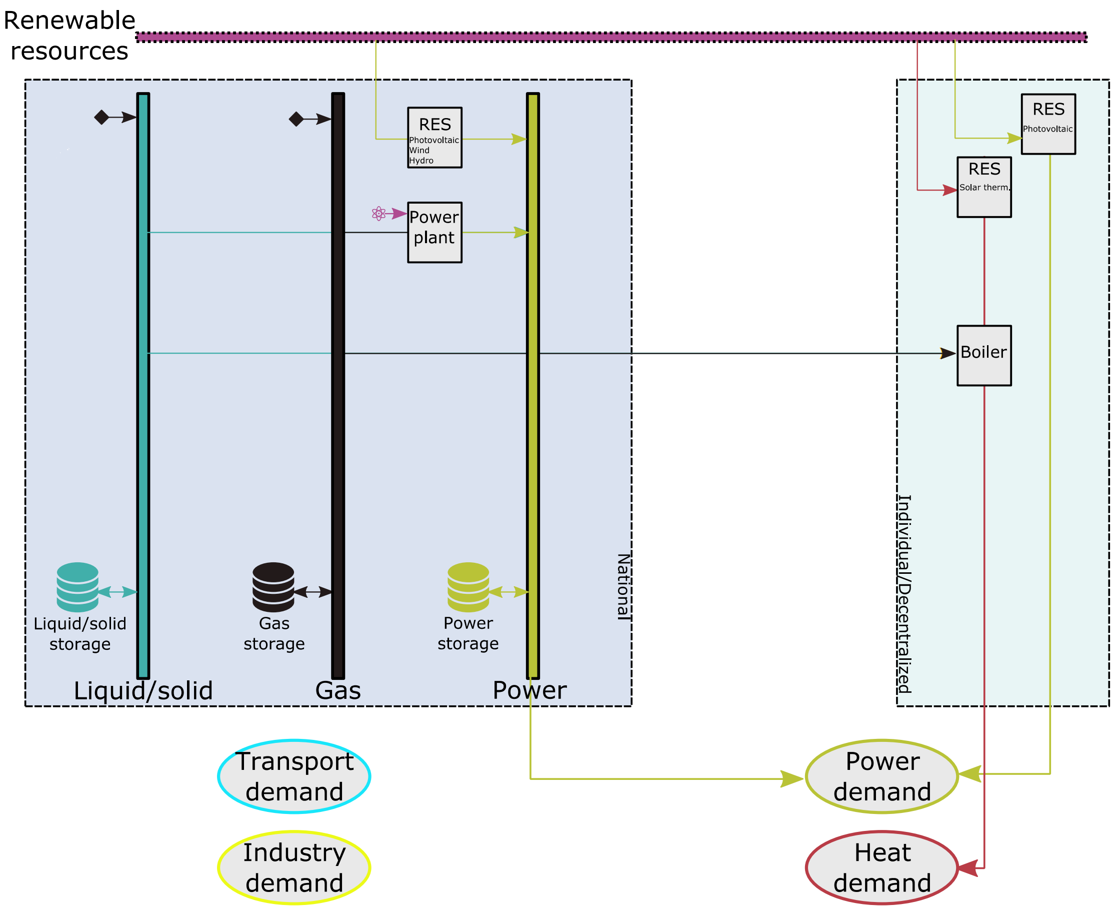

Figure 20. Conceptual view of the conventional energy sector

Accordingly, the EU Strategy on Heating and Cooling stresses the importance of integrating different energy sectors as one of the solutions to accommodate higher shares of variable renewable energy sources (VRE), mostly wind and solar (European Commission 2016). By creating synergies and connections among different carriers, the energy system can benefit in a faster way rather than taking an isolated view and strategy. In this regard, the main decarbonisation pathways rely on the electricity sector as it is the most mature wide-scale energy carrier and can lead to rapid decarbonisation trends.

The energy system, as depicted in Figure 21, could be configured to achieve an effective heat and power sector coupling in the future. The integration can be applied at different scales; at national level via utility scale plants, at a regional/local level though district networks or even at an individual installations/ household level by the use of decentralised generation and storage technologies.

Power-to-x technologies enable the conversion of energy sources into more flexible energy carriers at national scale. This group of technologies includes combined heat and power, power to gas or power to liquid solutions. They configure the new supply side of the energy system together with the existing power plants and the growing energy generation from renewable sources.

Looking into the regional/local scope, a new layer emerges connecting the supply and demand sides in the future integrated energy system. Traditionally, this layer is built upon electric networks, including transmission and distribution, which enable the connection between centralised power plants and end users. In a more interconnected energy system, the role of additional elements such as thermal networks and thermal storage and efficient power to heat technologies is getting more relevant.

Last, the individual/decentralised layer incorporates additional energy options. In this respect, power to heat and CHP technologies in combination with thermal or electric storage increase the flexibility at the demand side. This enables consumers to produce and store their own energy or exchange it with the energy networks.

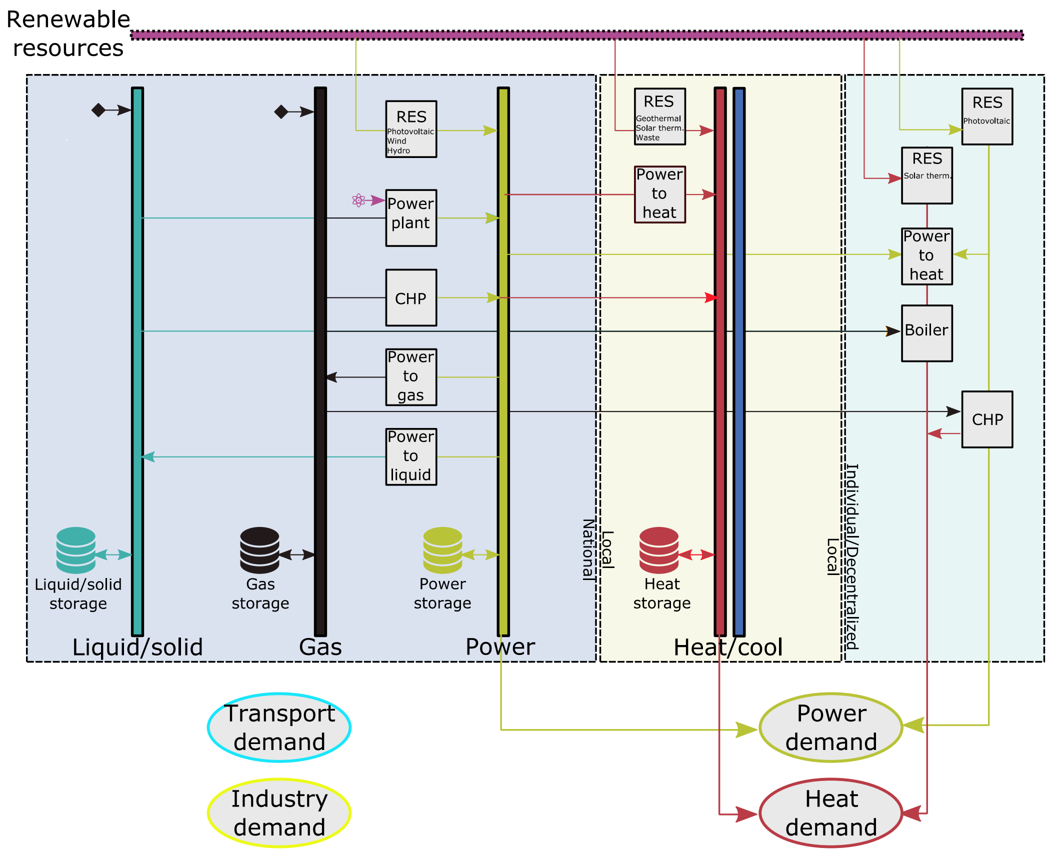

Figure 21. A conceptual view of sector coupling on different scales (national, local and individual)

3.2 Europe's power sector overview

To assess how an effective integration of the power and heating sector can benefit the overall energy system we need to first understand the nature of the power sector in Europe. It can be described by the operating power capacity per technology and the associated energy generation based on historical data. Both elements of the current (2016 data) and future (2050 projection) EU power sector, including Switzerland and Norway, are presented in this section.

3.2.1 Europe's operating power capacity

The current power capacity is dominated by fossil fuels (38%), followed by renewables, wind and solar, (27%), and hydro power (20%). Large differences are found across countries in Europe. Poland or the Netherlands, for example, rely mostly on fossil fuels (80% of the total installed capacity). On the contrary, Sweden and Switzerland do not show available power capacity based on fossil fuels. Looking into the renewable capacity, wind and solar, similar differences are found. Estonia (52%), Luxembourg (50%), Germany (46%) and Denmark (40%) lead the share of variable non-hydro renewable capacity. Contrary, Latvia (2%), Norway (3%) and Hungary (5%) show the lowest share of variable renewable capacity (European Commission 2016b). The above constitutes the current baseline power system for the rest of the study and is presented in Figure 22.

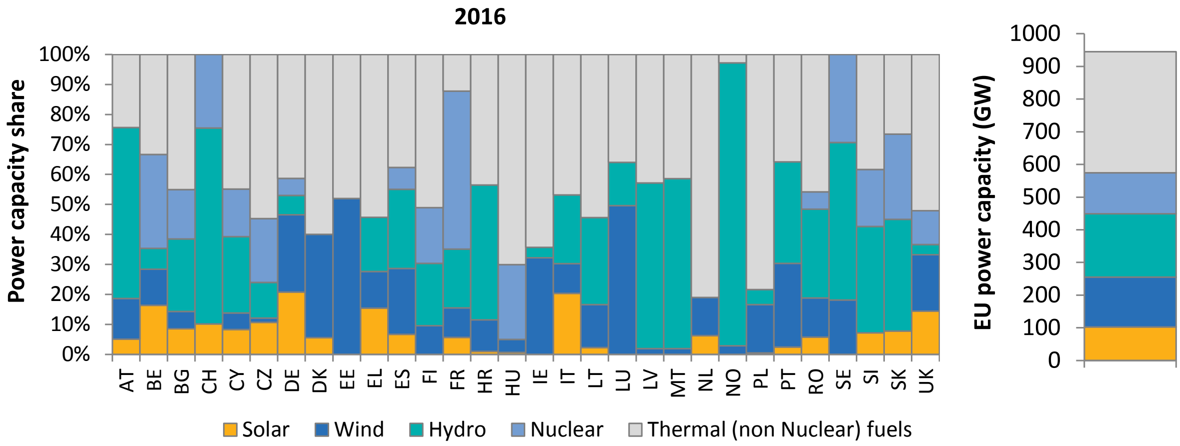

Figure 22. Power generation capacity and technology shares for today's EU (plus NO and CH) power system

In order to choose the most appropriate scenario to serve as our future baseline, we conducted a literature review of different scenarios both from the Commission (European Commission 2018; Keramidas et al. 2018) and other institutions (BNEF, Shell, IEA, Greenpeace). The results of this review are presented in Figure 23. Our selection was based on the following criteria: (a) to be realistic yet ambitious, (b) not to include extreme and skewed evolutions of individual technologies and (c) availability of data on a Member State level. Eventually a scenario close to LTS – ELEC and JRC-GECO-15C was generated based on an extrapolated version of EUCO30 as it represented a median non technology biased decarbonization scenario for 2050. A more detailed view of this scenario is shown in Figure 24.

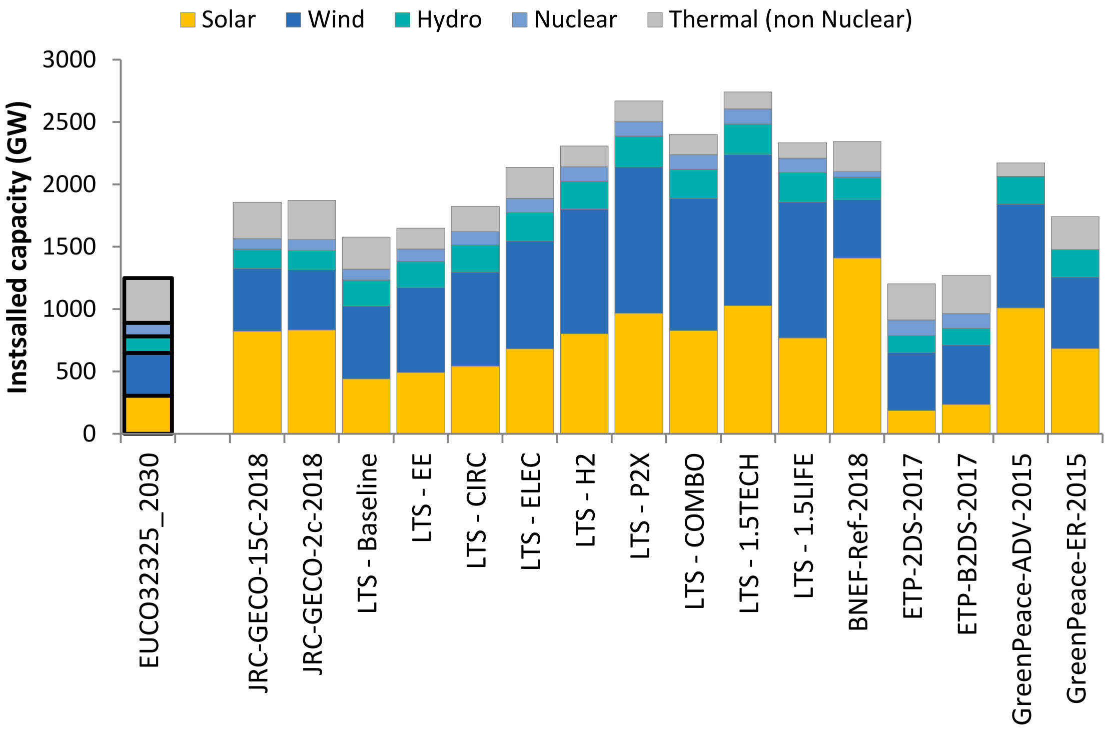

Figure 23. Power generation capacity for different scenarios in 2050. For reference the first bar shows the official scenario EUCO32325 for 2030

According to this scenario the power capacity will be doubled from 930 GW (2016 data) to 1 840 GW. A higher share of generation capacity from renewable sources is observed, 56% in 2050 vs 27% in 2016. The increase of renewables is experienced in every EU country. The RES growth rates ranges from a 50% increase in Latvia to a 4% in Luxembourg. On the contrary, the share of fossil fuels is reduced from 38% down to 22%.

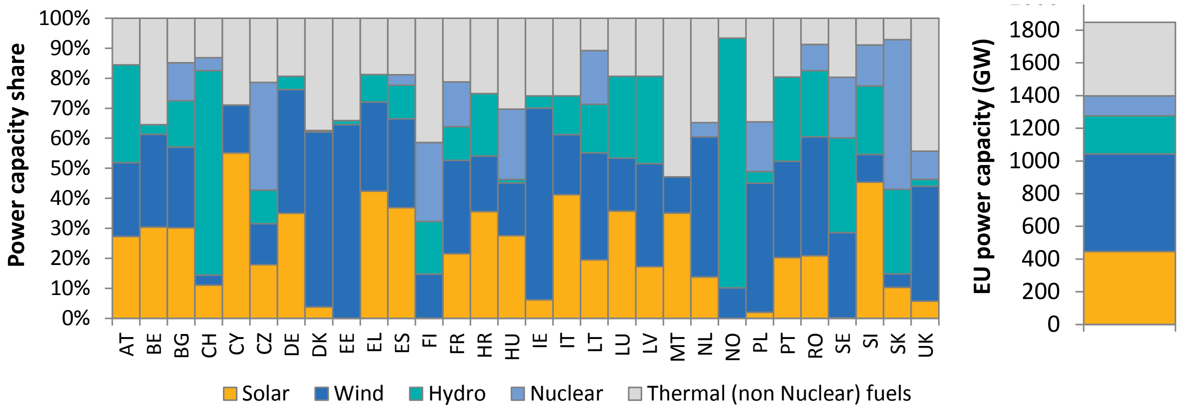

Figure 24. Power generation capacity and share per group of technologies for a future scenario

3.2.2 Europe's power generation

Today, the European power generation can be described by observing the load duration curves of the main technologies. These curves correspond to the generation which is sorted from the highest to the lowest value for one specific year. A load duration curve describes the peakiness (slope), maximum power (max value in y-axis) and the amount of energy generated (area under curve).

Figure 25 shows three years of power generation in Europe grouped by energy generation technologies. We observe that overall there are no dramatic changes among the three years. The generation and the peak generation of both the renewable (solar, wind, hydro) and peaker plants (gas) are increasing slightly. Currently, nuclear is the technology with the highest amount of electricity generated. This technology is also the less peaky, with an average load factor of 82%. Wind onshore is the first variable renewable energy source with the highest amount of energy produced.

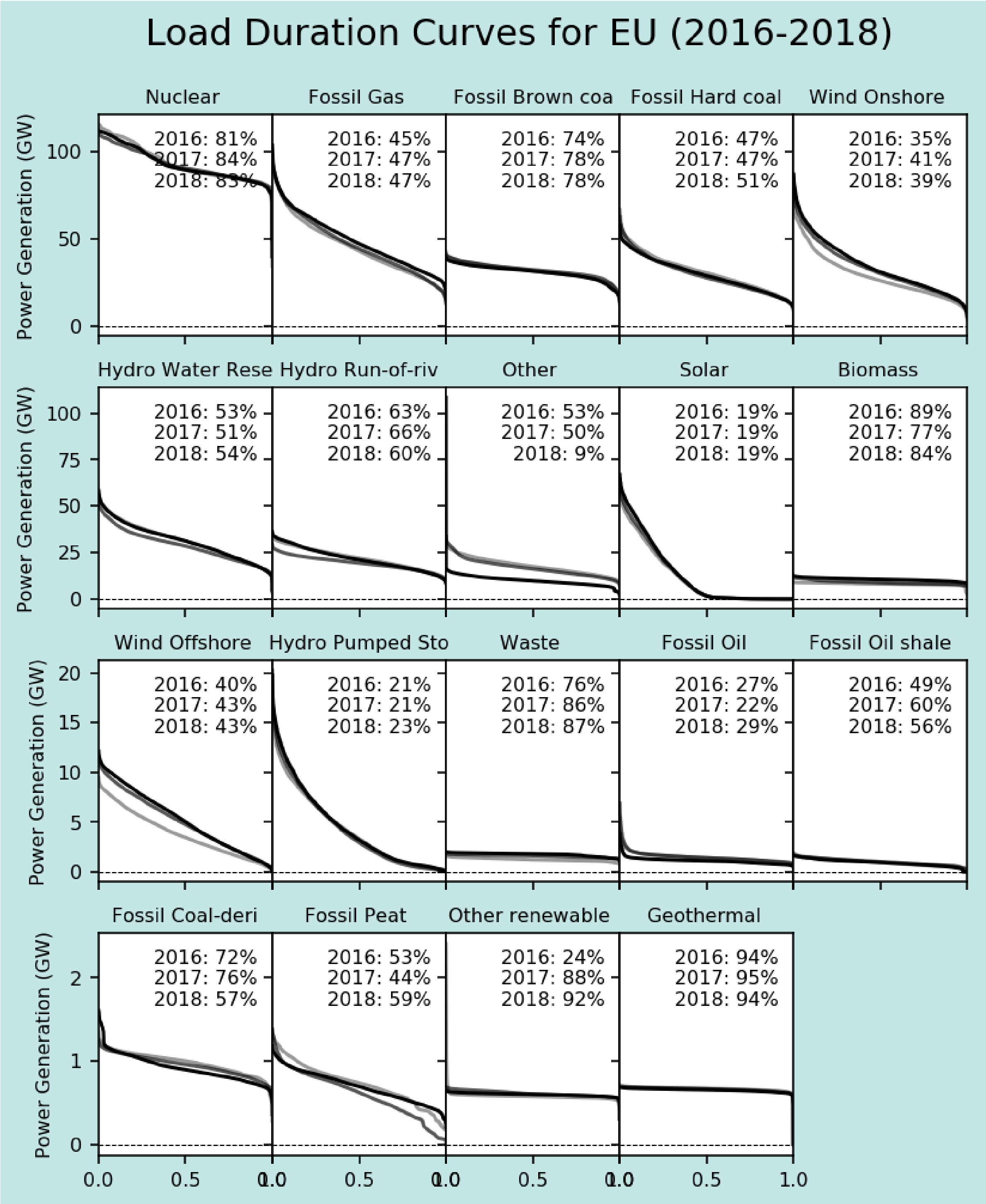

Figure 25. Historical Load Duration curves per technology for EU countries for 2015–2017. The darker line corresponds to 2017. The annotated percentages correspond to the capacity factor of each technology/year. The lower the number the more peaky the power generation of the technology is, i.e. the capacity needs are higher for the same energy served. NB.: Each row has separate y-axis scaling. X axis is normalised. Technologies are sorted by the amount of electricity generated (Area under curve)

3.3 Demand side integration of heat and power

Low-carbon heat can be provided in different ways, one of them being the coupling of the power and heat sectors at the demand side. This requires the electrification of the heat supply. It implies a rapid fuel shift replacing fossil fuels and in some cases even clean finite resources (e.g. biomass) that are competing among sectors. Electricity will be the main carrier under the described approach (Figure 26).

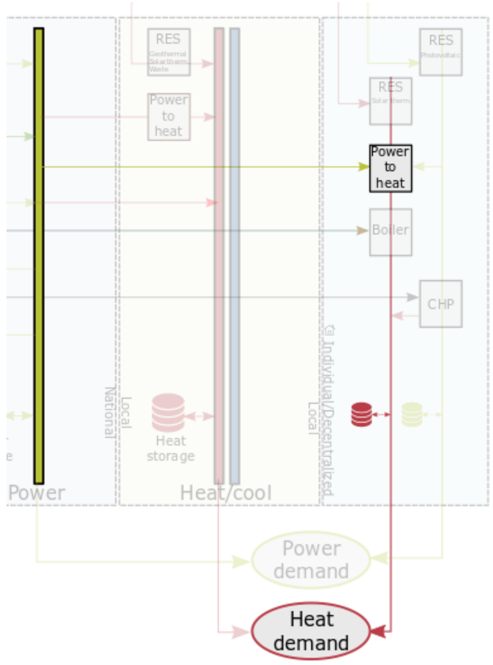

Figure 26. Focus on "electrification of heating" decarbonisation pathway. See Figure 21 for the whole picture

3.3.1 Benefits of electrification

Using electricity as the main energy carrier for satisfying heating needs has many benefits. This section examines why electricity is considered to be a favourable solution for heating and compatible with climate change mitigation targets.

A clean energy carrier

All energy carriers are racing towards a clean and decarbonised supply chain. The power is currently advancing as a mature and clean energy carrier that can be used to satisfy more end uses than it currently does. In the next paragraphs we examine the progress and readiness of the electricity system as an efficient and clean energy carrier.

One of the main indicators used in the policy is the primary energy factor (PEF) which shows how much primary energy is needed to generate one unit of electricity. This factor was estimated according to Eurostat definition. Currently, it is used in the Energy Efficiency Directive (EED) and Energy Performance of Buildings Directive (EPBD) having a fixed value of 2.5 to convert final energy consumption into primary energy consumption and consequently to monitor progress against targets. Figure 27 illustrates its evolution during the period of 1990 – 2016 for all Member States.

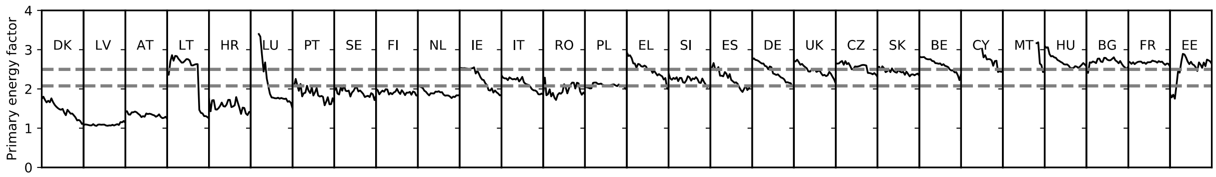

Figure 27. Primary energy factor of electricity as defined by Eurostat for different countries and years (1990 – 2016). Countries are sorted from the lowest current value to the highest (The lower the better)

While the primary energy factor is a good measure of system efficiency we define a modified indicator called fossil fuel intensity in an attempt to show a better measure of the decarbonisation of the power system and its readiness to a clean electrified economy. The fossil fuel intensity of the power system, is defined as the amount of fossil fuels (excluding uranium for nuclear) needed to be 'combusted' in order to produce 1 kWh of electricity. Figure 28 shows its evolution for the EU28 countries from 1990 – 2016 sorted by their corresponding values for 2016. The overall picture across the EU28 is diverse but overall the average fossil fuel intensity is falling from an average of 1.27 to 1.06 $kWh_{fossil}/kWh_{electric}$ for the period 2010 — 2016. Many countries have already achieved a fairly clean power system while others are experiencing a steep transition towards it.

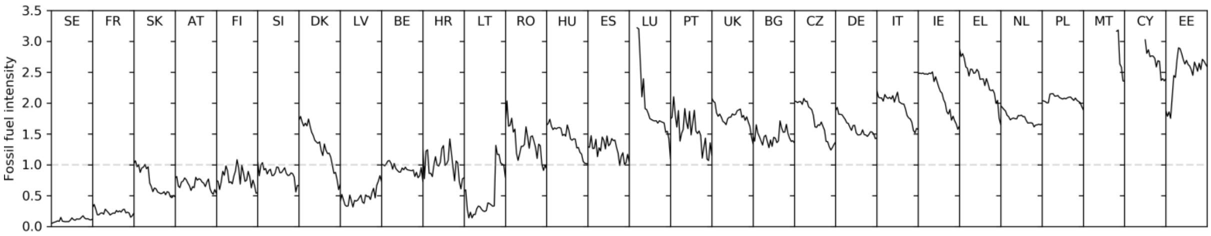

Figure 28. Fossil fuel intensity of power system for different countries and years (1990 – 2016). Countries are sorted from the lowest current value to the highest (The lower the better)

This is also reflected in the carbon intensity of heat produced by an average heat pump compared to a conventional gas boiler. Figure 29 shows the carbon footprint of one MWh_{th} provided by heat pumps and gas boilers – which were selected as a reference, due to them being the lowest emitting fossil fuel-driven competitor in that market segment. Regarding their utility for emissions reduction, we can see a clear trend in all member states towards heat pumps beating gas boilers, if not already the case. In countries with a strongly decarbonised power mix, such as Sweden and France which rely heavily on nuclear power, heat pumps are much more climate friendly than gas boilers. In more than half of the member states, heat pumps are already less carbon intensive. But even countries with a carbon intense power mix, such as Poland, the Netherlands and the Czech Republic are not far from parity.

Figure 29. Tons of CO_2-emissions per MWh of useful heat provided by heat pumps (blue) in comparison to conventional gas boilers (orange).

Figure 30 shows how the overall emissions of the heat and power sector are affected for different electrification rates and power system emission rates. The reason why we observe a saddle point for rates above 60% is because cleaner solutions such as biomass or district heating are getting replaced.

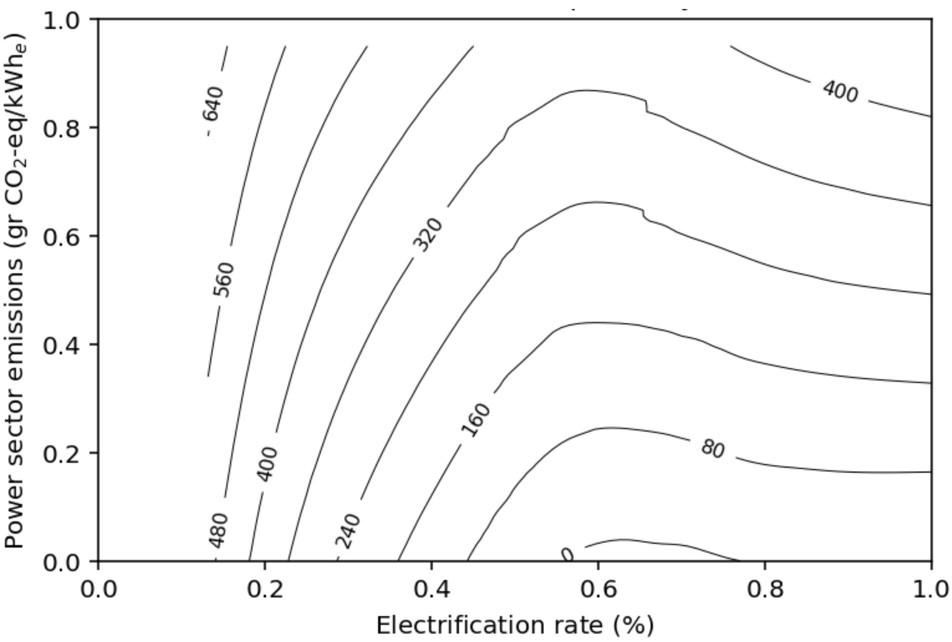

Figure 30. Contour plots of total emissions of the primary energy (Mt CO_2) needed to satisfy the heating demand for different degrees of electrification and power sector decarbonisation

A developed infrastructure

A further advantage of using electricity for heating is the utilisation of a highly developed transmission infrastructure. On a large scale, electricity is easier to transfer and to distribute than liquid fuels and even than heat itself. In some cases it may even be the only energy infrastructure available for the supply of heat since a gas or district heat network may not be available. The production chain of electricity is increasingly domestic in the European Union — due to the expansion of renewable energies — and the security of heat supply increases and import dependencies are reduced, enhancing the overall energy security. This is of particular interest in times where geopolitical developments and energy security concerns related to international relations and global trade are continuously growing.

Moreover there are services in the built environment that can only be fed by electricity. A continuous increase in IT, leisure and communication appliances, implies already an increase in electricity demand. That makes the power network irreplaceable. Building on top of this existing carrier infrastructure, its economies of scale, its advanced development and its modernisation prospect can favour also heat services.

Ready to be digitalised

Another benefit that electrification brings to the heating sector is that it opens a window to the digital economy. Power flows are easier to be 'digitalised' than water flows. This can allow a number of new services to appear such as automation, monitoring, remote control, demand response etc.

Flexibility services for the power system

In the past the generation side was able to change and meet the demand needs. In a future energy system the demand side should be more able to change its levels and meet the power generation supply coming mostly from an increased share of intermittent renewable energy sources. This concept is also known as demand response. From that point of view electric heating is a large source of flexible electricity demand that may facilitate this transition.

Electric-driven heaters will be able to stop and start their operation at a short notice without affecting much the thermal comfort of the residents, taking into advantage the building's thermal inertia. In that way generation can react to price signals; generate heat when prices are low (i.e. abundant supply) and stop the heat generation when prices are high (i.e. scarce supply).

For an even more pronounced effect thermal storage tanks can be added. Buildings can proactively learn the habits and the behavioural patterns of the occupants and pre-emptively shift the peak load to hours where electricity demand is low. This can be part of wider load shaping measures such as peak shaving, valley filling etc.

A very efficient and affordable technology

Electrification of heat can be either direct (resistive) or via geothermal, water- or air-based heat pumps, which have much higher conversion efficiencies. Heat pumps are the most promising electric-driven technology that can be used to satisfy the energy needs. Its operating principle is based mainly on the thermodynamic vapour compression cycle which is already tested and at an advanced technological readiness level. Not only it can be fed with grid electricity – which as discussed in previous section is becoming cleaner and cleaner – but it has very high efficiency compared to other technologies.

Electrifying the heating sector is also in line with the principle "energy efficiency first". Compared to other sources of primary energy, a heat pump (the main technology for electric-driven heating) is 3-5 times more efficient[4] than a normal boiler. This is achieved by upgrading very low value energy (such as ambient energy, geothermal etc.) to useful energy. Consequently this is reflected to the cost of the end-user as he needs to spend much less final energy in order to satisfy its thermal comfort.

From primary energy point of view even when we consider the conversion of electricity to primary fuel heat pumps are currently superior compared to other technologies. Figure 31 compares the average useful heat production per unit of primary energy input. The calculations are based on general and technology-specific efficiencies from IDEES power system efficiencies for each individual member state (EUROSTAT 2018). We can see that even taking into account the conversion processes in the power sector, newly installed heat pumps in the residential sector have been more efficient than the average stock since 2005.

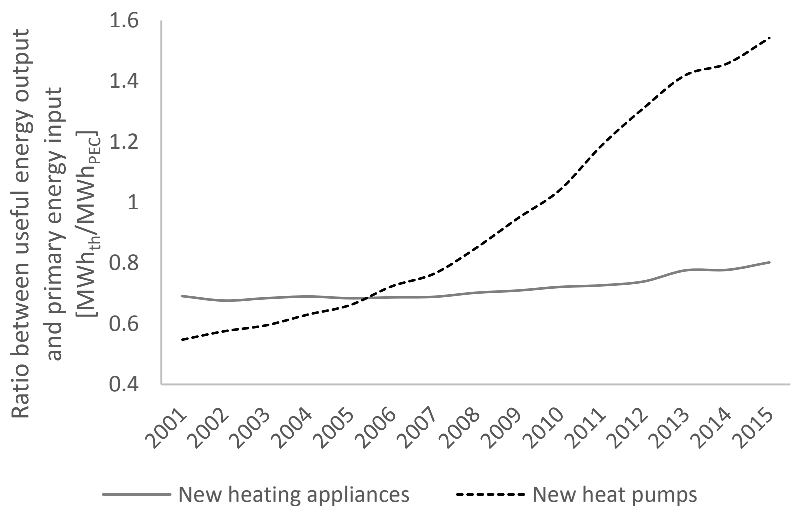

Figure 31. Performance with regard to primary energy consumption of heat pumps in comparison to the average new heating appliance in the EU28's residential sector

3.3.2 Challenges

The combination of the above benefits present heat pumps as the "low hanging fruit" that can reduce greenhouse gas emissions and increase energy efficiency. However, the above benefits will realise only if the power sector is decarbonised in an affordable way. Transferring the heat demand to the power system will cause increased peak during winter season. More specifically the electricity demand profiles will become

[4] This depends on the temperature difference between the desired Temperature and the temperature of the cold reservoir (e.g. ambient air, water body, ground etc). The smaller the temperature difference the more efficient it is.

"peakier" by increasing the slope of the load curves and with an increased dependency on the weather, since electricity used for heating is highly weather dependent.

Considering that in a future energy system the share of weather-affected renewable energy sources is increased, the overall exposure and risk of the power system to weather effects is magnified. When added with the sensitivity of the supply side this creates a higher overall weather dependency with the subsequent uncertainties and needs for a more modern and flexible market design.

In order to ensure the adequacy of the power system there may be a need for a combination of capacity, storage and reserves additions. Moreover, increasing power demand especially within energy dense urban centres will increase the stress to the distribution grid. If demand response mechanisms are not deployed fast of if they do not operate efficiently, the distribution networks will need to scale up and adapt to a smarter and more flexible way of operation and to new – more peaky – consumption patterns.

Apart from the power system implications, another challenge is linked to its affordability. Equipment costs of heat pumps are higher compared to conventional heat generating technologies. However like all new technologies an increased uptake will cause a faster industrialisation and standardisation of manufacturing and consequently it will lower the costs.

Installation can be also challenging in more dense urban areas where living space is more restricted as heat pumps need to have two installed units: One unit inside the heating space, and one in the reservoir from where the low quality energy will be abstracted (e.g. outside, ground etc.). The need for installing two units requires a larger space footprint and consequent increased installation costs. For small units usually covering the needs of one household installation costs can reach half of the cost of equipment (Hofmeister and Guddat 2017).

A last technical challenge is related to the nature of heat pump operation. The efficiency of a heat pump is inversely proportional to the temperature difference between the desired set-point temperature and the temperature of the low grade reservoir (e.g. ambient air, ground etc.); the higher the difference the lower the efficiency. On extreme temperature differences e.g. when ambient temperature is close to -10˚C there may be very low efficiencies and also reduced capacity.

A side effect of this technical particularity is that heat pumps are usually designed to operate at a lower temperature. Thus, buildings to be equipped with heat pumps need to be well insulated. The building renovation and installation costs may be a large barrier to the deployment of the above mentioned solution.

3.3.3 Literature review

In the literature, the role of electrifying heat as a cost effective measure to decarbonise the energy system is becoming more and more relevant (Bloess, W.-P. Schill, and Zerrahn 2018). As the lowest hanging fruit, heat pumps are key to reducing emissions in the heating and cooling sector and preferable to other sector coupling technologies (IWES/IBP 2017; Raghavan, Wei, and Kammen 2017; Schaber, Steinke, and Hamacher 2013). Their flexibility furthermore plays an important role in balancing power demand and supply, and may – in combination with other sector coupling technologies from transport and the chemical sector – render electricity storage redundant, even in a highly decarbonised system (T. Brown et al. 2018).

The electrification of heat is, however, highly dependent on an energy efficient building stock. The low supply temperatures of heat pumps render them much less efficient in buildings that are not well insulated, resulting in lower performance of the heating system. This has been identified as one of the key risks in focussing on a one-sided deployment of heat pumps for the decarbonisation of the heating sector and sparked a controversial discussion on the right strategy (Chaudry et al. 2015). Some studies argue that it is advantageous to decarbonise heating fuels through power-to-X technologies rather than investing in the cost intensive renovation of the building stock (DENA 2018; Enervis et al. 2017).

On a grid level, electrification creates new consumers which put the local infrastructures to the test. It has, however, been shown that even large penetration levels of battery electric vehicles and heat pumps are manageable if appropriate charging/operation strategies are implemented (de Boer-Meulman et al. 2010; Shao et al. 2013). In areas with distributed generation, heat pumps can even relieve the grid, if their demand response potential is utilised (Felten, Raasch, and Weber 2018). Moreover the amount of electricity demand from a heat electrification scenario is minimal compared to a transport electrification scenario. We will therefore not discuss this aspect further in this work.

Regarding the macro effects of heat pump deployment on the power system, there are two sides to the same coin: on the one hand, electricity consumption rises, which can create a need for capacity expansions and might produce additional CO_2-emissions in the power sector (depending on the electricity mix at hand) (Sandvall, Ahlgren, and Ekvall 2017). As there are strong signs in most EU Member States that heat demand exceeds electricity demand in both peak and annual demand, extensive electrification can place a heavy burden on the power system and require significant capacity expansion (Connolly 2017). On the other hand, heat pumps are a source of flexibility to the power system, which facilitate the reconciliation of electricity supply and demand in a system with high shares of variable renewable electricity sources, thereby reducing curtailment and fossil fuel consumption (Bloess, W. P. Schill, and Zerrahn 2018).

The effect on generation capacity levels cannot be seen as proportional to the heat pump uptake. We must rather distinguish according to the penetration level. At low penetration rates, in combination with thermal storage, heat pumps can lead to little or no additional required capacities to satisfy the additional demand. They can satisfy their needs in off peak times due to their flexibility (Baeten, Rogiers, and Helsen 2017). Separately, additional storage units are, however, no precondition for a flexible dispatch, since the thermal inertia of buildings can be used as a no-cost option for load shifting without impacting the comfort of the inhabitants (Heinen et al. 2017).

High penetration levels generate a demand for electricity which cannot be satisfied by just "filling in the gaps". This additional demand can generate new peaks and/or boost existing peaks, which leads to increased capacity requirements and requires additional investment in power generation capacities. Flexible operation still remains important to reduce the volatility of heat related electricity demand (IWES/IBP 2017; Ruhnau 2017).

The partial integration of heating into the power sector to build a more efficient overall system can only succeed if the two sectors are designed in the context of one another. The appearance of strong winds in fall and winter correlates with the heating period in central and northern European countries, which makes heat pumps and wind power a great match in this area (Hedegaard et al. 2012; Heinen et al. 2017; Vorushylo et al. 2018). Heat pumps can therefore help reduce renewable surpluses and enable further integration of wind power in systems with already a high penetration level of wind power(Hedegaard et al. 2012). Whether a flexible dispatch in combination with real-time pricing is economically profitable for the consumer, strongly depends on the electricity pricing regime (Felten and Weber 2018; Hedegaard, Pedersen, and Petersen 2017; Oldewurtel et al. 2010).

3.4 Supply side integration of heat and power

The use of available heat in centralised power plants can significantly reduce the GHG emissions associated with the heating sector. Power plants that can simultaneously produce heat and power, in a CHP mode, offer an opportunity to couple heat and power sectors at high efficiency rates. The heat produced in these plants can be distributed via thermal networks.

Thermal networks enable the use of highly-efficient heating technologies, waste energy sources and thermal energy storage. They tap the potential of economies of scale leading to an efficient and affordable heat supply. Areas with high heat demand such as densely populated cities offer the opportunity of aggregating heat demand and thus using heat networks in an effective way. In the following sections we describe the link between the heating and the power sector focusing on the supply side.

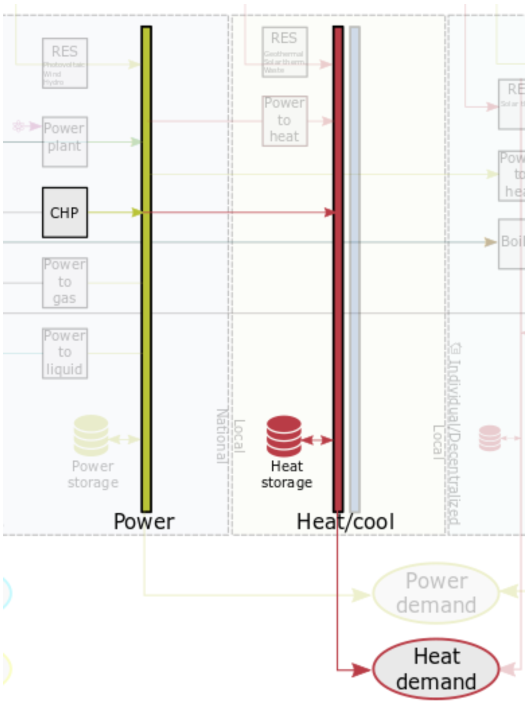

Figure 32. Focus on "centralised cogeneration with thermal networks" pathway. See Figure 24 for the whole picture

As mentioned in the Introduction another possible interaction of heating and power sector on a centralised level involves gas. More specifically, the clean e-fuel can be generated by the excess renewable electricity and feed the remaining thermal power plants fleet in the future. Renewable fuels can be produced by power to gas technologies (e.g. renewable hydrogen, bio methane) and the low carbon gas can serve as the main energy carrier. Such interaction is depicted in Figure 33. This gas could be transported, stored and distributed by the existing gas infrastructure, offering significant flexibility benefits to the grid according to van Melle et al. (2018)(van Melle et al. 2018)(van Melle et al. 2018). While these concepts may have considerable benefits but also adding extra complexity, they go beyond the scope of the heating sector and this study and will not be examined further.

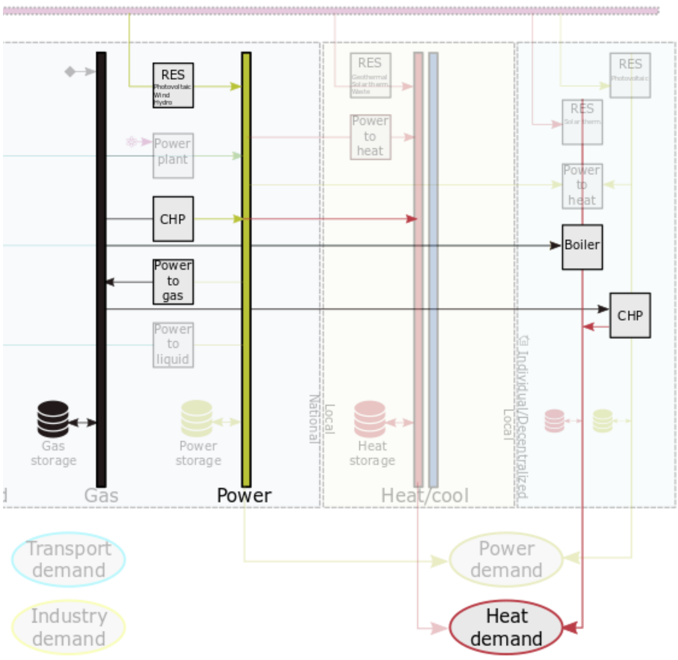

Figure 33. Alternative pathways to cover heat utilizing clean e-gas (power to gas)

3.4.1 Benefits and challenges of centralised heat supplied via thermal networks

This section examines the benefits derived from the use of centralised heat together with thermal networks and how it can contribute to the decarbonisation of the European heating sector.

High efficient centralised cogeneration

Combined heat and power (CHP) plants, which can reach a total efficiency of up to 90% (Grohnheit 1993), are an efficient asset to achieve the sector coupling at the supply side in the present energy system. They have been acknowledged as the most efficient way to generate useful energy from thermal power plants (European Union 2012). New emerging types of 'greener' fuels such as biomass, biomethane or even methane blended with hydrogen could benefit from such technologies and deliver both power and heat at the same time.

Existing steam-based power plants that are currently operating as power units, which can modify their operation to deliver heat and power simultaneously. This conversion leads to a significant reduction of the upfront investment costs compared to the cost of a new plant. For reference we present an extensive list of utility scale heat generation installations in Figure 34. The incremental capital cost of a CHP plant (compared to single purpose power generation) is at the same order of magnitude as the cheapest option (i.e. boiler). Therefore, the full potential of the centralised cogeneration relies both on existing CHP plants and power plants that can modify their operation to deliver both heat and power.

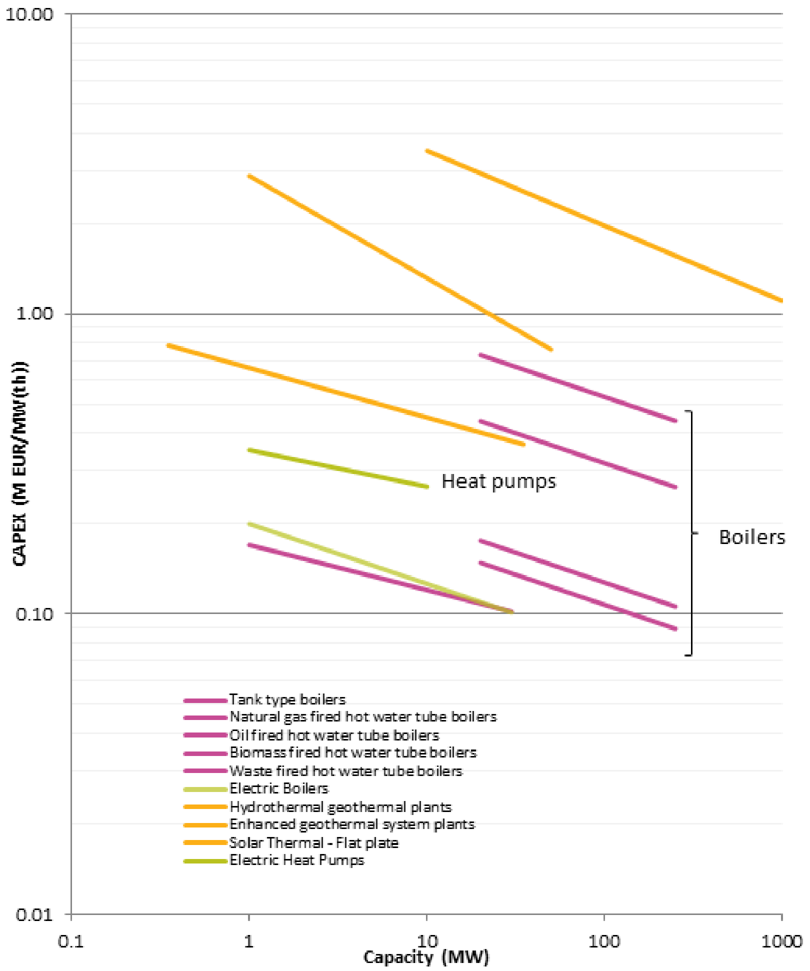

Figure 34. Specific capital cost for most common heat generation devices Data Source: (Grosse, Stefan, and Robbi 2017)

The disadvantage of converting steam-based power plants into CHP plants, from a technical perspective, is the reduction of the maximum amount of power that could be delivered individually. In other words, the higher the amount of heat produced the lower the maximum potential output power. So, a trade-off between the heat and power production is established for a given amount of input fuel. This power loss represents the power to heat ratio, equivalent to the coefficient of performance (COP) of a heat pump. Still, the combined production of heat and power leads to an increase of the overall efficiency compared to the single production of electricity. More detailed information on how different steam-based turbines can operate as CHP plants can be found in (Kavvadias et al. 2017).

From a policy perspective, it is argued that fossil-fuelled cogeneration plants should not be part of the future energy generation portfolio. On the contrary, several arguments support the utilisation of CHP plants in the medium- to long-term. First, driven by the high efficiency, they can play an important role along the transformation of the energy sector before being substituted by cleaner technologies. Second, current fossil fuels used in CHP plants can be replaced by biofuels. Last, a considerable fraction of the power generation capacity is expected to be base on thermal power cycel in 2050 (European Commission 2018). Such plants should be run in cogeneration mode in order to utilize the energy content of the input fuel in the most efficient and clean way.

Flexibility via thermal storage

The deployment of CHP plants together with thermal networks may unlock the potential of centralised thermal storage. Thermal storage is acknowledged as a cost-effective solution to balance heat generation and demand at all times (Lund et al. 2016).

Thermal storage can be integrated at different levels of the energy system, including national, local and individual/decentralised levels, according to the energy system layout presented in Figure 21. The use of thermal storage provides flexibility to the entire power system by enabling a more power-driven cogeneration. Thus, it facilitates a better integration of intermittent renewable energy sources through a more flexible operation of the CHP plants. This flexible operation allows higher CHP efficiency ranges as larger amount of heat can be produced and stored.

Thermal storage can be categorised by temperature range, periods of storage and location related to the application (De Vita et al. 2018). Three main thermal storage technologies exist. The main characteristics of these technologies are presented in Table 1.

Table 1. Techno-economic parameters for TES technologies (Sarbu and Sebarchievici 2018)

TES System	Capacity (kWh/t)	Power (MW)	Efficiency (%)	Storage periods	Cost (EUR/kWh)
Sensible (hot water)	10 — 50	0.001 — 10	50 — 90	days/months	0.1 — 10
Phase-change material (PCM)	50 — 150	0.001 —1	75 — 90	hours/months	10 — 50
Chemical reactions	120 — 250	0.01 — 1	75 — 100	hours/days	8 — 100

Roughly, thermal is 100 times cheaper compared to electric storage (Østergaard et al. 2016). This ratio may vary depending on the specific storage application on one hand and the rapid cost reduction that electric storage is experiencing on the other (Tsiropoulos I, Tarvydas D, and Lebedeva N 2018). Still, large-scale thermal storage solutions, which are required for thermal network applications, are more cost-effective than the storage of electricity (Figure 35).

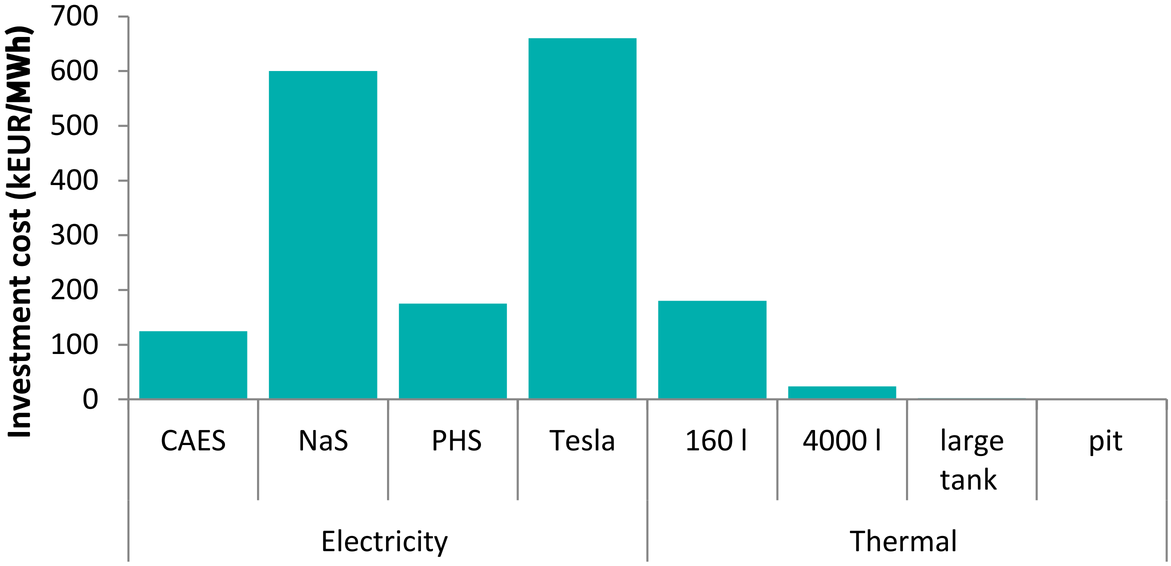

Figure 35. Investment cost per unit of stored capacity of electric and thermal storage options (Østergaard et al. 2016)

Thermal networks

The lack of available thermal networks to distribute the cogenerated heat is the major bottleneck when it comes to the utilization of new cogenaration plants. The deployment of thermal networks entails significant upfront investment costs that could hinder the utilisation of centralised heat and power technology solutions under the supply side sector integration.

Currently, district heating networks supply only ten percent of the total heat supply worldwide, however high disparities between countries are identified. Yet, district heating solutions have a strong potential to be feasible if adequate energy planning is done (Werner 2017). Thermal networks have been proven feasible in dense urban areas with concentrated heat demands. In this application, both investment costs and thermal losses are reduced (Reidhav and Werner 2008). Therefore, centralised power plants relatively close to urban areas are the ideal scenario.

In addition, the new generation of district heating networks, also known as 4th generation of district heating systems (Lund et al. 2014), can contribute to a larger use of centralised CHP plants. They are characterised by lower temperatures of operation that enable the utilisation of additional heat sources and reduce the heat transmission losses. Moreover, led by low temperatures, large amounts of heat can be transferred in a cost-effective way to large distances of the order of tens of kilometres (Kavvadias and Quoilin 2018).

Use of available heat sources

In addition to the heat produced in centralised power plants, the deployment of thermal networks can enable the utilisation of available heat sources that are currently wasted. The use of these sources can alleviate the power system load maximizing the utilisation of renewable energy sources. The deployment of low temperature networks, 4th generation of district networks, will allow incorporating more heat sources even those with poorer quality from an exergy perspective (low temperature resources).

Challenges

The major challenge relates to the deployment of thermal networks. They have been proven feasible in many applications. Yet, they have not been fully deployed in countries with no tradition (Werner 2017). For those countries, raising awareness is essential.

The conversion of combined cycle power plants into CHP plants can also represent a challenge. Originally, these power plants were designed and built to maximise the production of power. Therefore, companies operating this type of plants are reluctant to modify their operation unless income deriving from the heat supplied compensates the economic losses from the lower power production.

New business models, including the involvement of public authorities, have to be developed to guarantee the viability of thermal networks. Other aspects such as the raise of user awareness, the development of engineering skills and a reliable regulatory framework should be developed to achieve a large deployment of thermal networks (Millar, Burnside, and Yu 2019).

3.5 Summary

The above sections are summarised in the following Table 2 where the benefits and challenged are presented seperately for the power and the heat sector. While they are presented as three discreet choices the reality is that a combination of all three to a specific extent will be the optimal solution. Such combination has to be carefully planned to avoid no-regret investment in infrastructures. Such overlaps in infrastructure investment not only may prove costly but may lead to stranded assets when different market conditions arise.

Table 2. Summary of possible heat-related energy transition pathways

	Electrification	**Cogeneration and District heating**	**Power to Gas**
Heating sector			
Benefits	Increased efficiency	Utilises waste heat; increased energy efficiency	Large existing capacity; existing grid
Challenges	Negative feedback on low temperatures (increased demand – low efficiency)	Heat as a carrier more difficult to handle than electricity; limits in transmission	Depending on the type of gas (hydrogen, biomethane) small or large adaptation will be needed on applications and infrastructure
Investment needed	Building renovations and heat pump equipment	Heat networks and retrofits	Depending on the type of gas (hydrogen, biomethane) small or large adaptation will be needed on applications and infrastructure
Power sector			
Benefits	Renewable integration; increases flexibility	Utilises any fossil or renewable fuel in the most efficient way	Renewable integration, network Infrastructure already mature
Challenges	Stresses the power system in specific times of the day and days of the year	Reduces flexibility	Expensive and not mature conversion technologies; Injecting and blending green gas into current grid could be challenging
Investment needed	Flexibility measures and capacity additions	Minimal: retrofits on steam based plants	Not yet cost efficient conversion technologies; increase of CO_2 price necessary for a business case

4 Heat sector scenarios and their impact on the EU power system

This section introduces the scenarios proposed to assess the benefits derived from the integration of the power and heat sectors. We focus on two families of scenarios: advanced heat electrification (as described in Section 4.1.2) and advanced deployment of centralised CHP and district heating scenarios (as described in Section 4.1.3).

Each scenario will be defined by a heat and power demand and a power plant fleet. In additional, national heat efficiencies and costs are required to characterise the conventional heat supply per country. This heat supply option will allow evaluating the cost-effectiveness of supplying heat from centralised CHP plants. To guarantee a fair comparison framework, demands remain constant for all the scenarios under a given time horizon — current and future (2050).

To evaluate the impact of the sector coupling on the power system, we use an in-house state of the art power system model with features specifically developed to simulate the EU power system and its link with the heating sector. Section 4.2 includes more details on its main features, assumptions and recent developments tailored for this study.

All power system simulations and analysis are done for EU28 excluding Cyprus and Malta due to their island nature, and lack of data. Norway and Switzerland are included in the power system simulation due to their important role but they are not included in the aggregate EU results. These two countries are only considered from the power but not from the heating perspective.

In the following subsections we define in detail the scenarios and describe the modelling framework.

4.1 Definition of Scenarios

The major aspects that describe the families of scenarios under study are listed below.

- Base case
  - Current: power plant fleet power and heat demand as of today
  - Future scenario: Power plant fleet based on the scenario described in section 3.2 and total heat demand based on Heat roadmap Europe baseline scenario. For the sake of comparison no additional energy efficiency measures are considered.
- Heat Electrification scenarios
  - Overnight electrification of fossil-based heat of the current power system which will serve as a stress test for the current situation
  - Different degrees of heat electrification of the future energy system. Sensitivities are also examined such as adding more storage, interconnections, more renewables or load shaping measures (i.e. Peak shifting).
- Cogeneration and district heating scenarios
  - Use of combined heat and power generated in centralised power plants and delivered via district heating as a high efficient option to serve both heat and electricity needs
  - The role of thermal storage is examined in those scenarios. As an additional flexibility option, thermal storage enables larger integration of renewable while guaranteeing an efficient heat supply from centralised cogeneration power plants
  - The feasibility of thermal networks is also assessed via a sensitivity analysis based on the heat density demand requirements and distances between heat sources and demand.

4.1.1 Base case

Two base case scenarios were developed according to the current and expected future status of the energy system by 2050. These scenarios set the comparison framework to examine how the proposed sector coupling strategies benefit the entire energy system in terms of cost, efficiency, emissions, and integration of higher shares of renewables among others.

They are defined by the following input elements:

- the power plant fleet as described in Section 3.2,
- energy demand (including electricity and heat),
- national heating efficiencies and associated fuel costs.

Power plant fleet

The power plant fleet used in the proposed scenarios is presented in section 3.2 for the current (Figure 22.) and future (Figure 24.) energy system.

Heat and power demand

Current base case scenario is based on the structure of the heating sector of 2015 and the weather year of 2016. Furthermore we created a family of scenarios to investigate the possible effects of future heat pump deployment for different electrification rates. Heat and power annual values are already presented in section 2.1 and the annual time series in section 2.3.

Power demand

To build the current scenarios, we have retrieved the hourly power demand from the European Network of Transmission System Operators for Electricity (ENTSO-E) database for the year 2016.

4.1.2 Heat electrification scenarios

This group of scenario assumes a turn to electric-driven heating. Our aim is to investigate the impacts that different degrees of electrification have on the power system as well as the environmental and energy efficiency benefits that might arise from an increased heat pump deployment. To this end, we compare the base line scenario (BLS), to scenarios which vary in their degree of heating sector electrification: The E20 – E100 scenarios describe a step-wise replacement of decentralised fossil and resistive electric heaters by heat pumps. The number in the scenario name refers to the replacement rate of fossil fuel driven technologies, i.e. 100 implies that all fossil fuel technologies are replaced with heat pumps. These technologies were chosen, since they are the less clean or inefficient technologies in the European heating sector. These electrification scenarios can be understood by assuming that decentralised heating applications fuelled by gas, oil, coal, as well as resistive heaters are substituted by heat pumps overnight. For the sake of comparison the end-use demand remains the same in all scenarios. However, the technology mix and consequently the final energy consumed changes.

The E100BIO scenario assumes a displacement of biomass in the heat sector. We chose this scenario, since there is great competition for biomass from the industrial and the transport sector, as well as only a limited potential (European Environment Agency 2013). To quantify the maximum impact of electrification, the E100ALL scenario describes a European heat sector, in which all space heating is satisfied by heat pumps. This scenario, albeit not realistic, serves as an upper limit and frames the analysis. All scenarios have been constructed at a national level. Table 3 and Figure 36 give an overview of all scenarios, depicting the final energy consumption according to fuel.

Table 3. Useful heat demand covered by electricity for different Member States and scenarios

	BLS	EL20	EL40	EL60	EL80	EL100	EL100BIO	EL100ALL
AT	1.9	2.4	2.9	3.5	4.0	4.5	6.3	9.1
BE	3.5	5.3	7.2	9.0	10.8	12.7	13.2	13.4
BG	1.7	1.5	1.4	1.3	1.2	1.0	1.7	2.3
CY	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
CZ	3.2	3.7	4.2	4.7	5.2	5.7	7.5	9.7
DE	15.7	27.2	38.7	50.3	61.8	73.4	81.9	92.9
DK	0.8	1.0	1.2	1.4	1.6	1.9	3.0	6.9
EE	0.4	0.4	0.4	0.4	0.4	0.4	0.7	1.4
EL	3.2	3.3	3.4	3.6	3.7	3.9	4.7	5.1
ES	8.8	10.0	11.2	12.4	13.5	14.7	17.3	17.7
FI	5.3	5.1	4.9	4.7	4.5	4.3	5.8	10.0
FR	28.5	31.8	35.0	38.3	41.5	44.8	52.5	56.3
HR	0.8	0.9	1.0	1.1	1.2	1.3	2.4	2.6
HU	1.1	1.9	2.6	3.4	4.1	4.9	6.6	7.4
IE	1.0	1.5	2.0	2.5	3.0	3.5	3.6	3.7
IT	8.7	13.8	18.9	23.9	29.0	34.1	40.6	42.9
LT	0.3	0.3	0.3	0.4	0.4	0.4	0.9	1.7
LU	0.2	0.3	0.5	0.6	0.7	0.8	0.9	0.9
LV	0.2	0.3	0.3	0.3	0.4	0.4	1.0	1.7
MT	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.3
NL	3.5	5.6	7.8	9.9	12.1	14.2	14.9	15.7
PL	5.0	7.1	9.2	11.3	13.4	15.5	18.2	25.4
PT	1.7	1.7	1.6	1.6	1.5	1.5	2.3	2.6
RO	0.9	1.5	2.1	2.7	3.3	3.9	6.6	8.0
SE	9.9	9.2	8.5	7.9	7.2	6.5	7.5	13.1
SI	0.5	0.5	0.6	0.6	0.7	0.7	1.2	1.4
SK	0.9	1.2	1.5	1.8	2.0	2.3	2.4	3.1
UK	19.9	26.2	32.4	38.7	44.9	51.2	53.0	53.7
TOTAL	127.9	164.1	200.3	236.5	272.7	308.9	356.9	409.4

Figure 36 shows the final energy consumption of the scenarios examined. The conversion of useful energy to electricity needed is based on the demand/temperature in order to account for variable efficiency as a function of temperature is presented in later in this section.

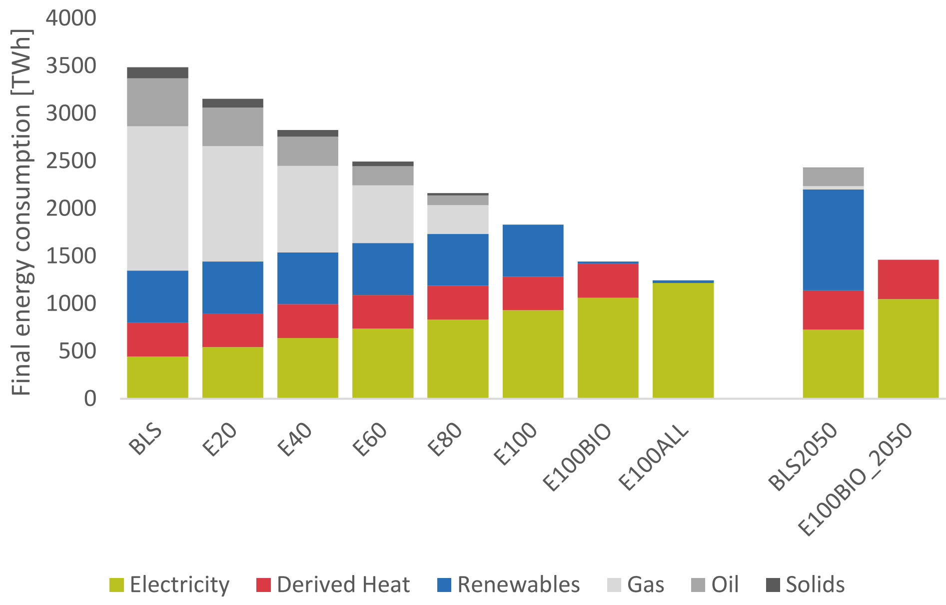

Figure 36. Final energy consumption for space heating in EU for different electrification scenarios

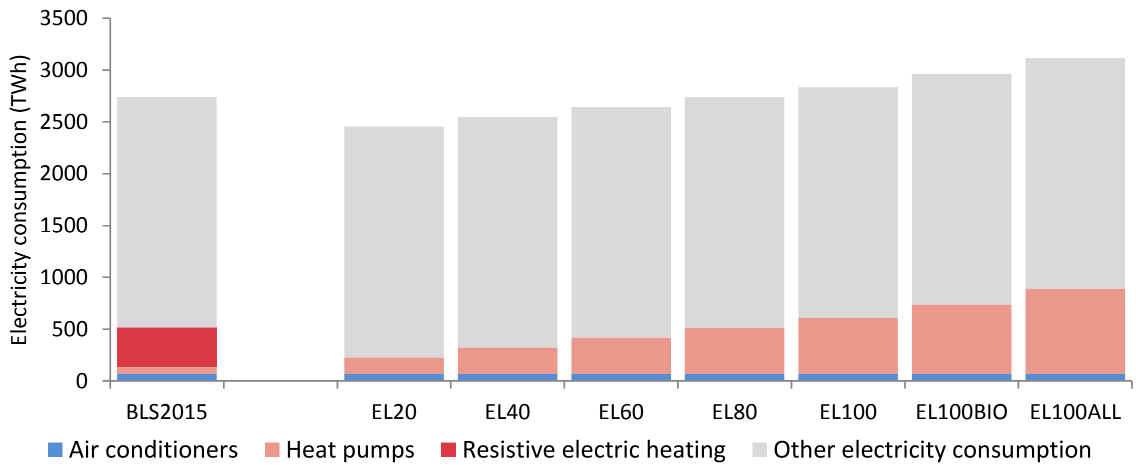

Figure 37. Comparison of electricity consumption per end use in the baseline and the incremental electrification scenarios

Heat pumps make up 26% of final electricity consumption or 540 TWh in the EL100 scenario. The spread of heat-related electricity shares is small across member states, since specific heating and cooling needs are of a similar magnitude. Higher heat related shares are not so much based on the geographical location of the country.

The electrification rate is 55% for the EL100 scenario and 77% if also biomass based heating solutions are replaced (EL100BIO). This is not very close to the assumptions of other studies such as the one from Eurelectric (Eurelectric 2018) which shows electrification rate of the final demand in buildings up to 63% or the one from Shell (sky scenario) that considers a rate of 74%. On the other hand, International Energy Agency ETP B2DS scenario is more pessimistic considering an electrification rate of only 35%.

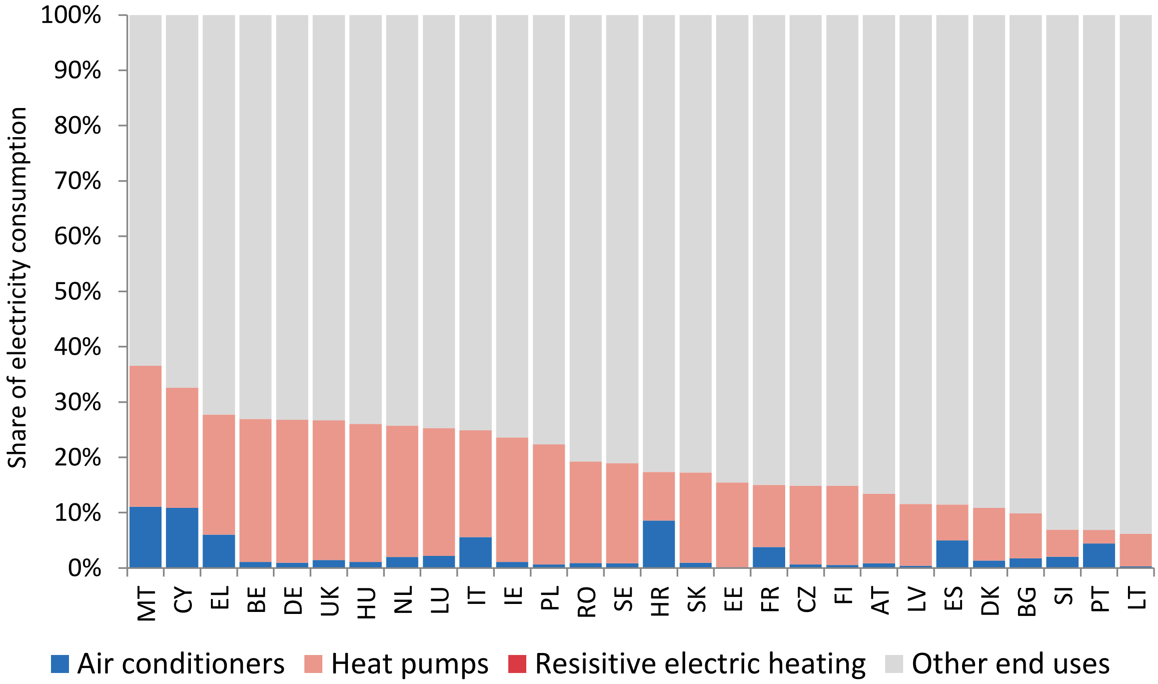

Figure 38. Heating and cooling share of electricity demand per Member State in a full heat electrification scenario EL100 (based on 2015 demand) (excluding process heat and cooling)

Demand curves

The heavy burden, which electrification places on the power system can be seen in Figure 39. It shows the load duration curves for the different scenarios. The seasonal profile of heat demand leads to large increases of electricity demand throughout the winter half of the year. The steeper profile of the load duration curve shows a large increase in volatility and therefore a small amount of hours with a very high demand. Demand side flexibility could reduce this number of hours, spreading out the peak demand more evenly. Yet, taking the amount of firm capacity into consideration leads us to believe that the E60 scenario seems to be the most ambitious electrification scenario which can be secured by today's firm capacities.

The contribution of RES capacities to satisfying this demand must be judged very cautiously. The peak occurs in all European countries in December or January after 16.00, meaning that solar panels cannot contribute to satisfying this demand. Relying on wind power, on the other hand, risks the heat supply of residential citizens in years when wind lulls occur and cold weather coincides (Huneke, Perez Linkenheil, and Niggemeier 2017).

The decomposed curves presented in Section 2.2 and Annex 2 were scaled to correspond to the total amount of energy indicated above. For the generation of the new time series we did the following. Using the temperature time series presented in Section 2.2 we estimate the implied coefficient of performance (COP) time series based on a Carnot factor by means of:

$COP_t = n_c\,(1\text{-}T_{set}/T_{out,t})$

where, second law efficiency of η_c =45% and a setpoint Temperature of T_{set} = 22°C is used.

With the above we can simulate successfully the effect of cold spells which affects the heat pump efficiency negatively. Peak heat demand coincides with low efficiencies, causing high demand for electricity. While this does not occur often, it creates a positive feedback loop. When the space heating demand is the highest, then the efficiency of a heat pump is the lowest increasing the electricity demand even more. This effect is obvious in the Load duration curves shown in Figure 39.

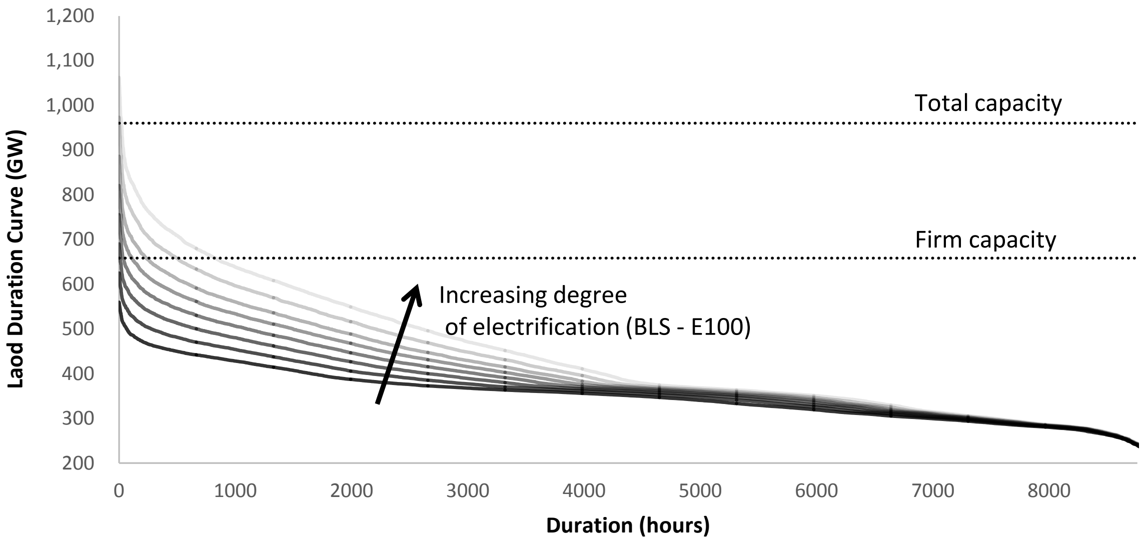

Figure 39. Load duration curve for different electrification scenarios. Today's firm and total power generation capacity is presented for reference.

Electrifying the part of the heating sector implies an increase in winter peak from 20 to 70% higher than today. Figure 40 shows how the peak demand would increase compared to the base scenario if all fossil fuel would be replaced by heat pumps. A more detailed view of the distribution of load before and after the electrification is shown in Figure 39 in the form of a load duration curve.

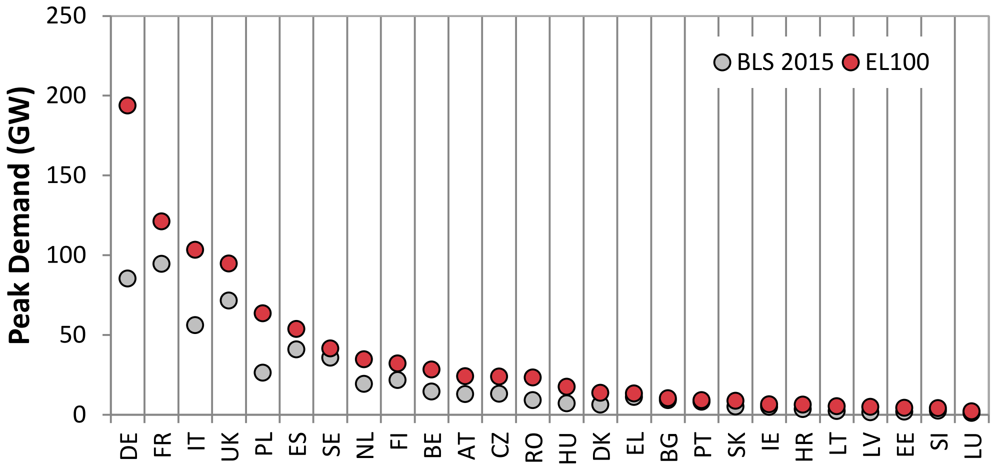

Figure 40. Peak demand for 2015 for the base case (BLS 2015) and the full electrification case (EL100)

Figure 41 shows the time and magnitude of electricity peak demand across the EU member states. It illustrates that peak demand times across the member states lay very close together: Electricity demand in Belgium, Germany, France, Italy, Luxembourg and the Netherlands peaks on the same day, with the electricity demand in Austria, the Czech Republic, Romania and Bulgaria reaching its peak in the same week. This positive correlation puts a lot of pressure on the central European power system in middle of winter (Figure 41).

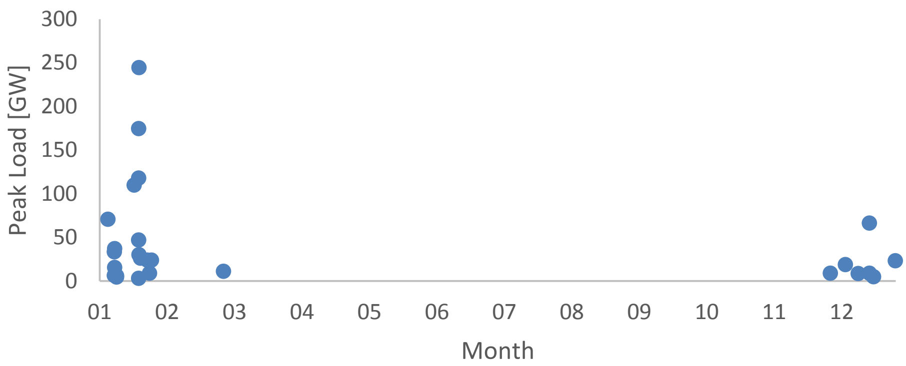

Figure 41. Date and magnitude of electricity peak demand in EU countries

Just as the heat sector is quite heterogeneous across the EU, heat electrification has very different impacts on a country level. For demonstration purposes, we selected four different countries, which vary strongly with regard to their heat sector structure and their geographic location, and estimated their power sector's fitness for different electrification scenarios: Figure 42 shows the weekly peak demand for Belgium, Spain, Croatia and Sweden, normalised by the country's firm capacity level. Belgium was selected as a typical western European country with large shares of gas boilers, Spain as a southern European member state with a mild climate and a diverse heating sector structure. Croatia has a large share of biomass boilers, which is typical for eastern European countries, and Sweden as northern European country relies largely on district heating and also heat pumps already today.

Figure 42. Weekly peak demand for 4 different countries normalised by the country's firm capacity level

The geographical location of each Member States clearly seems to have an impact. The share of decentralised fossil boilers in Spain's heat sector is more than 60%, yet the complete electrification of the Spanish heat sector would only result in tolerable increases in demand. The current structure of the sector and the building stock, however, does play a major role: the Swedish electricity demand in all scenarios never exceeds the firm capacity, even though it is located much further to the north than any of the other member states. Belgium on the other hand sees peaks 1.8 times greater than its firm capacity, even though the climate in Belgium is milder. This is due to Sweden having an energy efficient building stock and a high share of district heating and heat pumps.

Climate and energy efficiency benefits from electrification

As long as decentralised fossil fuelled boilers are replaced, electrification proves to be an effective strategy: Figure 43 shows the changes in CO_2-emissions as well as primary energy consumption in the heat and the power sector between the base case and the E100 scenario. In this scenario, where fossil fuels have been completely pushed out of the heating sector, all countries benefit from electrification with regard to both, emissions reduction and energy efficiency. Most notably France, which would reduce its joint emissions from heat and power by 65% and its primary energy consumption in these sectors by roughly 45%. This is due to the fact that their heating sector still consists of over 55% of oil and gas boilers today, and that they have a low carbon electricity system, primarily based on nuclear power. Northern and north-eastern EU member states appear to benefit the least from increased electrification, simply because they have already a small share of low carbon heating. The impact is higher in western and central European countries of all latitudes, such as the United Kingdom, Germany, Italy and Belgium, due to their high share of decentralised heating applications. Poland and Estonia do profit from efficiency gains, yet only achieve low carbon savings. This can be attributed to their carbon intensive electricity mix, which heavily relies on coal, in the case of Poland, and oil (Estonia).

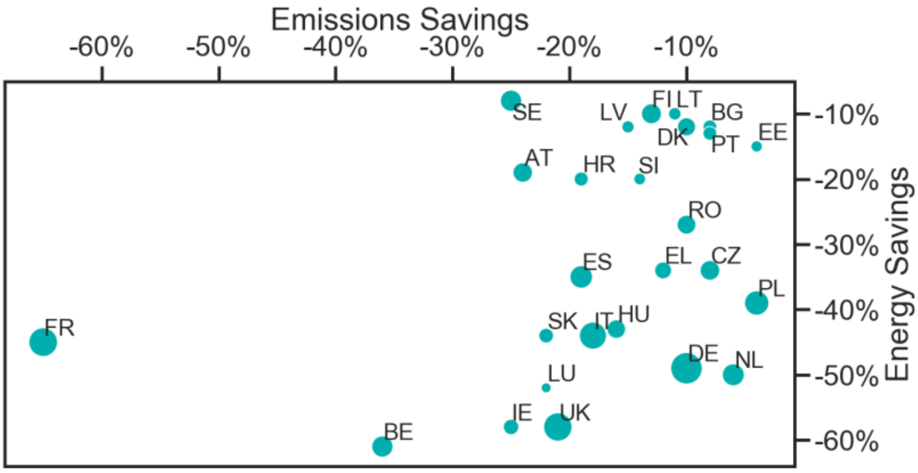

Figure 43. Comparison of BLS and E100 for the current energy system.
NB: Bubble diameter is proportional to the square root of useful energy demand

A summary of the generated scenarios is presented in Table 4.

Table 4. Summary of the different generated electrification scenarios in a current context

	Fuels replaced	Electrification rate	Peak demand for electricity (GW)
BLS	Base case	13%	560
EL20	Fossil fuels (20%)	18%	625
EL40	Fossil fuels (40%)	24%	690
EL60	Fossil fuels (60%)	32%	755
EL80	Fossil fuels (80%)	42%	821
EL100	Fossil fuels (100%)	55%	886
EL100BIO	Fossil fuels and biomass	77%	973
EL100ALL	Fossil fuels, biomass and district heating	100%	1062

4.1.3 Cogeneration and district heating scenarios

The cogeneration and district heating scenarios examine the potential benefit of centralised combined heat and power plants and heat storage systems. For this purpose we assume that fossil fuelled steam-based power generation (combined cycle power plants) can operate providing heat to nearby demand areas (Figure 44).

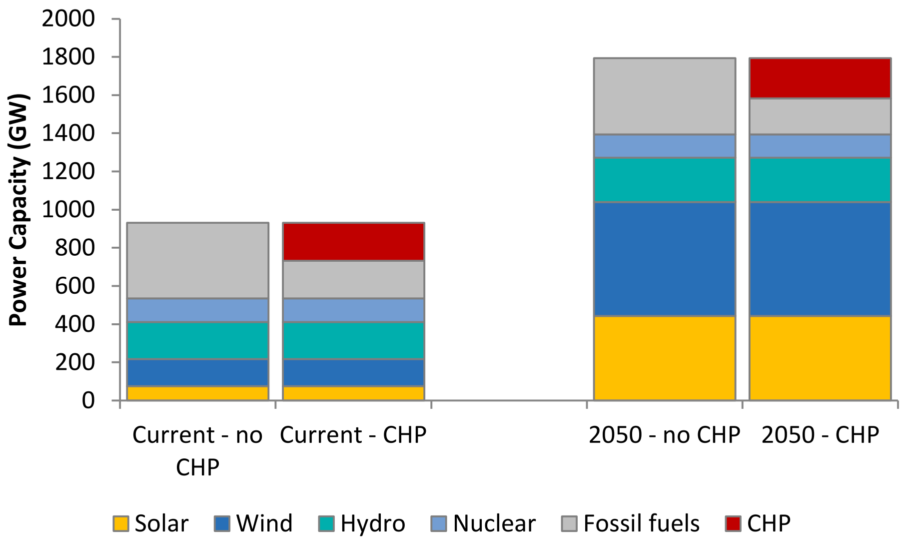

Figure 44. EU Power generation capacity for current and future scenarios including CHP and no CHP alternatives

Three scenarios are developed based on the potential heat demand that can be delivered from these plants:

- All heat is able to be utilised by heat networks. Under this full potential scenario it is assumed that suitable heat sinks are available to serve the total heat produced at the plants via district heating networks.
- Only medium and high density areas are able to utilise cogenerated heat.
- Only high density areas are able to utilise cogenerated heat.

While it may not be realistic to consider that the required district heating networks are in place to transfer all heat from centralised plants to the demand sites, the evaluation of such scenarios is valuable in order to assess the maximum potential that can be realised.

In addition to the different levels of heat demand considered, the role of heat storage is investigated. The incorporation of thermal storage will enable a more efficient operation of the CHP plants and thus benefiting the energy system as a whole. In this study, we focus on its availability rather than finding optimal sizing. As a result, we assume large sizes at country level.

Based on the above elements, several scenarios are defined based on the available centralised heat capacity and thermal storage, the power fleet and the electric demand for the timeframe considered, and the heat demand that could be served from the converted power plants. Details of the different assumptions and input data to build these scenarios are presented below.

Characterisation of the heat demand

As for the rest of the cases included in this study, the scenarios focus on the space heating and domestic hot water uses for the residential and service sectors representing the entire built environment. In particular, centralised heat generation targets heat demand currently supplied by fossil-fuel based technologies (fossil heat demand) (Figure 45). Thus, heat from electricity and renewables remains unchanged in these scenarios. The same applies for the space cooling and other uses.

Thus, if we compare the current base case scenario (Figure 3) with the full potential scenario, the share of heat from fossil fuels for space heating decreases from 62% to 27% (district heating increases from 11% to 43%). In the case of domestic hot water, the district heating share increases from 8% to 37%.

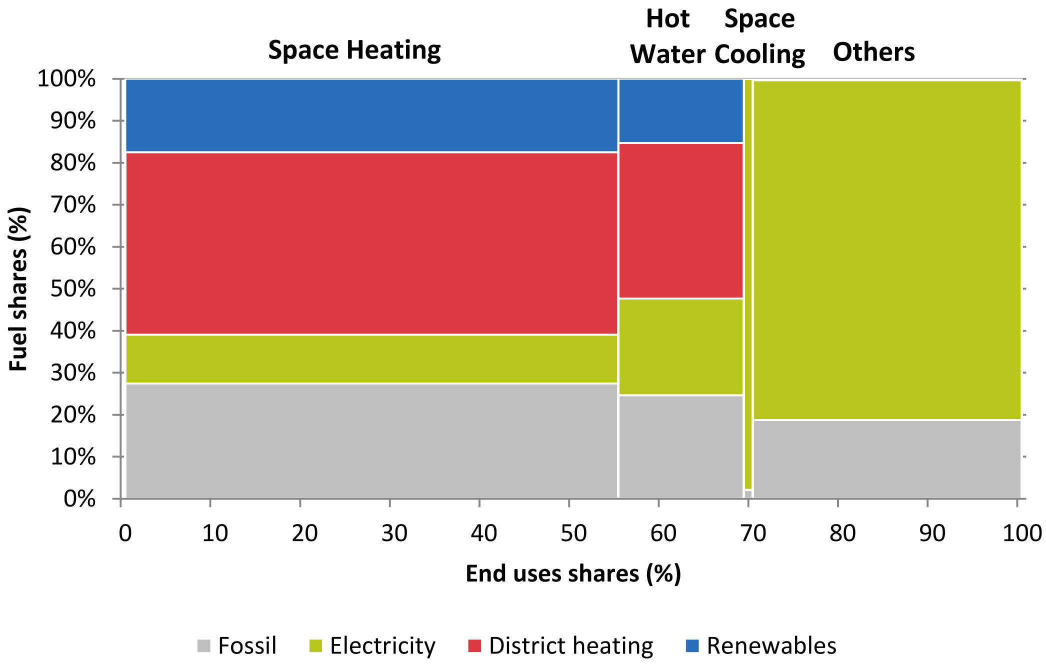

Figure 45. A comprehensive view of useful composition of the built environment for different uses and fuels in the EU. based on the current CHP full potential scenario

Combined heat and power plants

This scenario assumes that the fossil power plants that fossil fuelled steam-based power generation (combined cycle power plants) can be converted into CHP plants providing heat to nearby demand areas. The power plant conversion has been modelled based on the model for extraction condensing turbines presented in previous work (Jiménez Navarro et al. 2018). According to the current development of district heating networks, a supply temperature of 100 °C has been considered. This temperature is a conservative assumption as future thermal networks seek to operate with lower temperatures that lead to an increased efficiency of the CHP plants (30 – 70 °C — 4th generation of thermal networks (Lund et al. 2014)).

Conventional heat supply

The heat demand not covered by centralised CHP plants is provided by a virtual heat supply plant defined per country. This plant is characterised by the national average efficiency and average cost of the heating sector. To calculate the national average input fuel costs we have consulted national statistics on electricity, gas, and oil for heat:

— Gas and electricity prices for household consumers (Eurostat 2018).

— Average prices of heating oil in European countries. 2000 to 2017 time series (Statista 2018)

This input data as well as estimated efficiencies and costs were presented in section 2.1.

Centralised thermal storage

The incorporation of thermal storage in these scenarios aims to assess how storage can maximise the utilisation of the heat produced in centralised plants and thus increasing the overall efficiency of the system and reducing costs. An available storage capacity equal to the maximum daily generation is considered to accompany each plant (Figure 46).

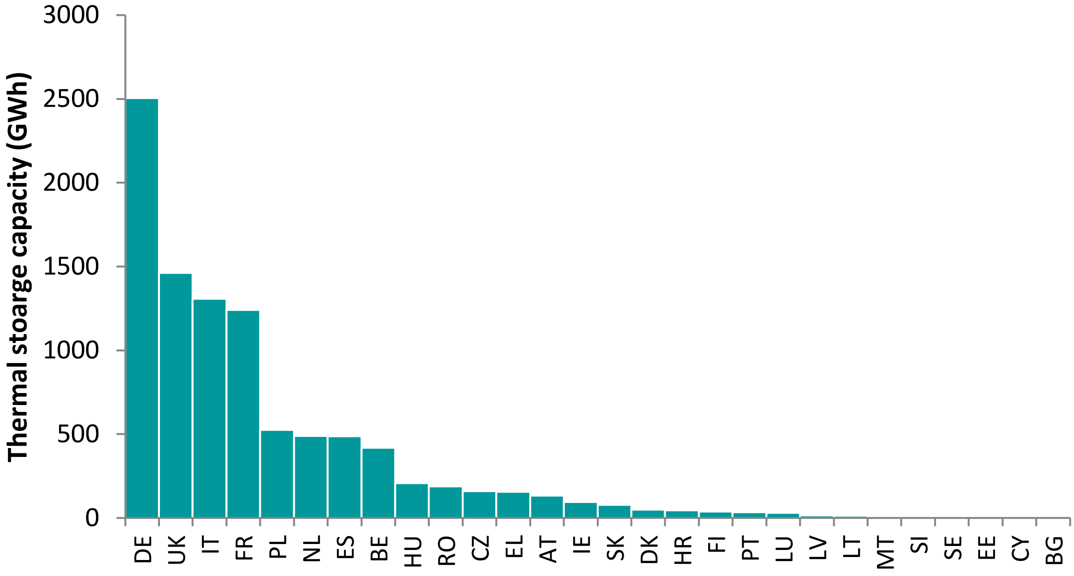

Figure 46. Thermal storage capacity per country — Current scenario

This capacity turns out to be enough to enable the efficient heat production. Put in different words, daily storage cycles are enable an optimal dispatch for cogeneration units. Thus, the assumption on the size simplifies the analysis on the benefits of the thermal storage.

Technical potential

As a further step in the analysis of the deployment of the cogeneration and district heating pathway, additional scenarios have been set based on the availability of high heat demand density areas that could be supplied via district heating in a cost-effective way. Thus, only areas with heat demands densities (TJ/km2) above a certain threshold are considered to be supplied from centralised CHP plants in a cost-effective way. In addition, only those areas that are less than 100 km away from thermal plants that can operate as CHP plants have been accounted.

The required geographical information on heat demand areas has been retrieved from the Pan-European Thermal Atlas Peta v4.3 developed in the framework of the Heat Roadmap Europe 4 (HRE4) project. The thermal atlas is so far available for 14 EU countries. Therefore, results are limited to these countries (Europa-Universität Flensburg and Halmstad University 2017). In the case of the power plants, we have considered the geographical information available in the JRC Power plant database (Kanellopoulos et al. 2017).

Based on the heat demand density levels defined in HRE4 Europe, two levels are assessed: > 120 TJ/km2 (medium heat demand density areas), > 300 TJ/km2 (high heat demand density areas). Figure 47 shows the total heat demand for the different density levels considered for the 14 EU countries available. Some countries are zero as they have no thermal power plant nearby.

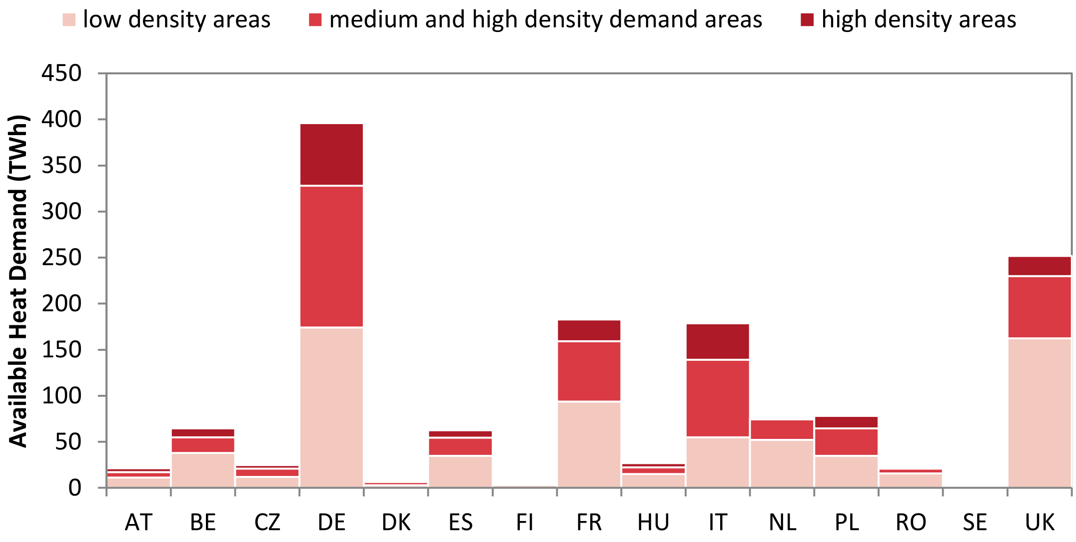

Figure 47. National useful energy heat demand for different technical potentials: high (> 300 TJ/km2), medium (> 120 TJ/km2 and < 300 TJ/km2) and low (< 120 TJ/km2) demand areas

Figure 48 shows the results of the geospatial analysis carried out to determine the amount of the energy demand that can be supplied from thermal power plants considering a maximum distance of 100 km between supply and demand. For a given thermal plant (x-axis), the number of areas within a 100 km radius (left y-axis) is accounted as well as the closest heat demand area to each power plant (right y-axis). Figure 49 presents the specific location of the different heat demand areas (polygons) as well as the location of thermal power plants.

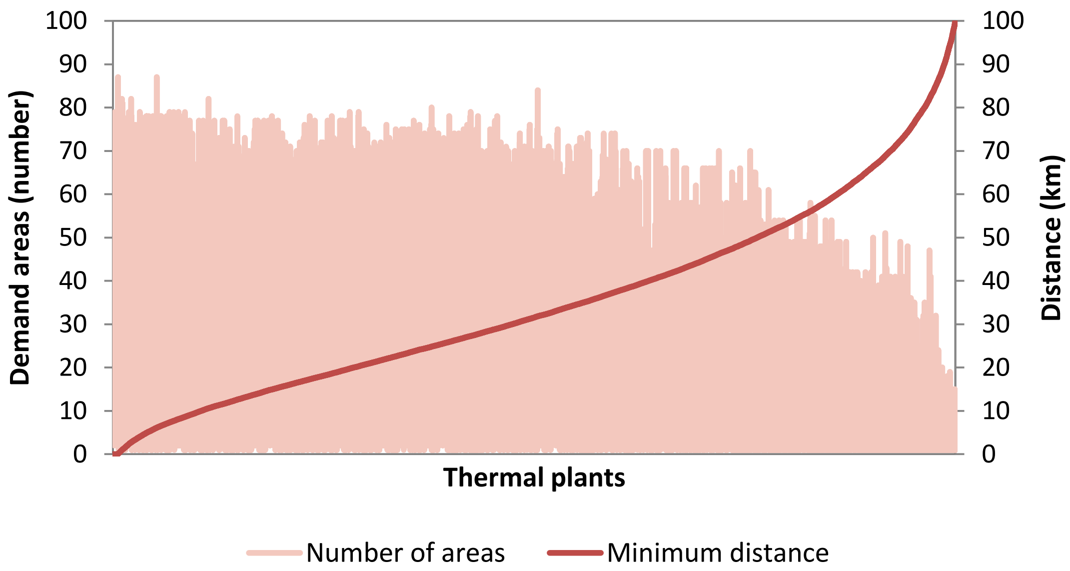

Figure 48. Geospatial analysis on heat demand areas less than 100 km far from the thermal power plant fleet. On the x axis plants are sorted by their proximity to the closes demand area.

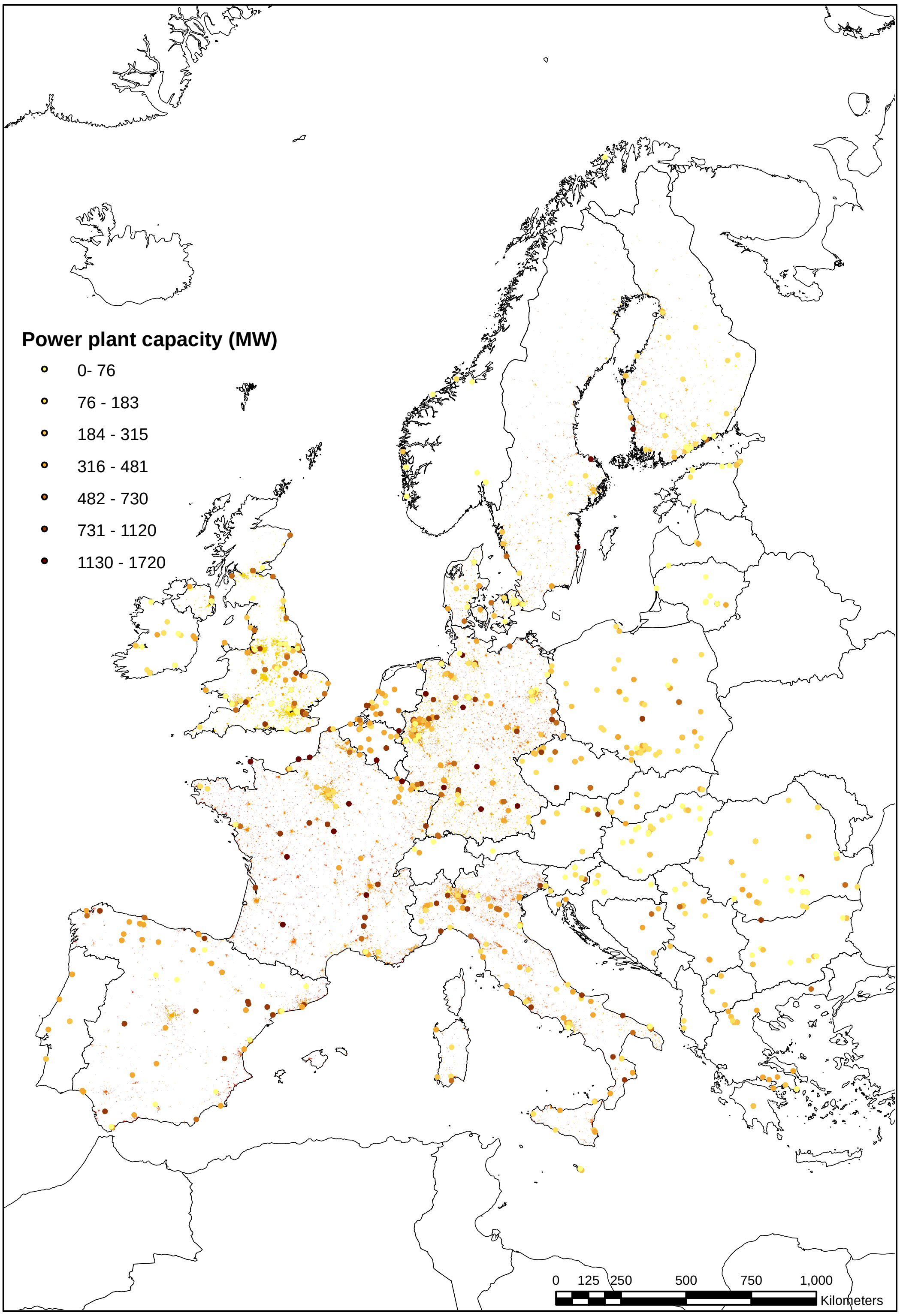

Figure 49. High density heat demand (14 EU countries) and thermal power plants (EU)

4.2 Modelling framework details

The simulations were based on just released open-source model Dispa-SET v2.3. (http://www.dispaset.eu). This is the first public study that is performed with the new version which has some features specifically for an European-wide simulation, not included in other public models.

Dispa-SET (Kavvadias et al. 2018; Quoilin, Hidalgo Gonzalez, and Zucker 2017) is an existing unit commitment and dispatch model. The aim of the model is to represent with a high level of detail the short-term operation of large-scale power systems, solving the unit commitment problem. To that aim, it is considered that the system is managed by a central operator with full information on the technical and economic data of the generation units, the demands in each node, and the transmission network. The main model features can be summarised as follows: minimum and maximum power for each unit, power plant ramping limits, reserves up and down, minimum up/down times, load shedding, curtailment, pumped-hydro storage, non-dispatchable units (e.g. wind turbines, run-of-river, etc.), start-up costs and ramping costs.

The unit commitment problem consists of two parts: i) scheduling the start-up, operation, and shut down of the available generation units, and ii) allocating (for each period of the simulation horizon of the model) the total power demand among the available generation units in such a way that the overall power system costs are minimised. The first part of the problem, the unit scheduling during several periods of time, requires the use of binary variables in order to represent the start-up and shut down decisions, as well as the consideration of constraints linking the commitment status of the units in different periods. The second part of the problem is the economic dispatch problem, which determines the continuous output of each generation unit in the system.

The problem mentioned above can be formulated as a MILP problem. The formulation is based on publicly available modelling approaches (Tom Brown, Hörsch, and Schlachtberger 2018; Carrion and Arroyo 2006; Morales-españa, Latorre, and Ramos 2013). The goal of the model being the simulation of a large interconnected power system, a tight and compact formulation has been implemented, in order to simultaneously reduce the region where the solver searches for the solution and increase the speed at which the solver carries out that search.

Since the simulation is performed for a whole year with a time step of one hour, the problem dimensions are not computationally tractable if the whole time-horizon is optimised. Therefore, the problem is split into smaller optimisation problems that are run recursively throughout the year. A common setting for this approach is the following: the optimisation horizon is one day, with a look-ahead (or overlap) period of one day. The initial values of the optimisation for each day are the final values of the optimisation of the previous day. The look-ahead period is modelled to avoid issues linked to the end of the optimisation period such as emptying the hydro reservoirs or starting low cost but non-flexible power plants.

Simulations were run with the new integer clustering formulation, in which all units of a similar technology, fuel and zone are clustered. A typical unit is defined by averaging the characteristics of all units belonging to the cluster. This formulation divides the simulation time by a factor higher than 10 and allows extending the geographical scope of Dispa-SET. The total number of units is conserved, allowing a proper representation of constraints such as start-up costs, minimum up/down times or minimum stable load values. This is the main innovation compared to other models that represent country level aggregated fleets which ignore constraints such as thermal units, start-ups and shutdowns with associated costs and constraints.

Simulations were run in a cluster node with the following characteristics: 2x Intel Xeon E5-2690 v4, 2.60GHz, 14-core processors (in total 28 cores), 256GB of DDR4-2400MHz ECC memory. Each simulation took from 3 to 10 hours to be completed.

4.2.1 Objective function

The goal of the unit commitment problem is to minimise the total power system costs which are defined as the sum of different cost items, namely: start-up and shut-down, fixed, variable, ramping, transmission-related and load shedding (voluntary and involuntary) costs. The demand is assumed to be inelastic to the price signal. The MILP objective function is, therefore, the total generation cost over the optimisation period. The variable production costs are determined by fuel and emission prices corrected by the efficiency and the emission rate of the unit. The start-up and shut-down costs are positive variables, active when the commitment status between two consecutive time periods is modified. The objective function is formulated as follows:

$$C^{tot} = min \sum_{n \in \boldsymbol{N}} \sum_{\boldsymbol{u} \in \boldsymbol{U}} \sum_{t \in \boldsymbol{T}} \left(C_{\boldsymbol{u,t}}^{fix} + C_{\boldsymbol{u},t}^{start} + C_{\boldsymbol{u},t}^{var} + C_{\boldsymbol{u},t}^{ramp} + C_{t,l}^{trans} + C_{n,t}^{shed} + \sum_{chp} C_{chp,t}^{CHP} + C_{n,t,u}^{VOLL} \right)$$

where C^{tot} are the total operation costs (€); $C_{\boldsymbol{u,t}}^{fix}$ are fixed costs (€) of running the unit, u, in all time periods, t; $C_{u,t}^{start}$ are the start-up costs (€) and $C_{u,t}^{var}$ are variable costs of all units, u, and all time periods, t; $\mathrm{C}_{\mathrm{t,l}}^{\mathrm{trans}}$ are transmission costs (€) directly depending by the flow transmitted through the lines, l; $\mathrm{C}_{\mathrm{chp,t}}^{\mathrm{CHP}}$ are costs (€) associated to the CHP plants, chp; $\mathrm{C}_{\mathrm{n},t}^{\mathrm{shed}}$ are load costs (€) associated to the necessary load shedding and $\mathrm{C}_{\mathrm{n},t,u}^{\mathrm{VOLL}}$ are costs of lost load (€) associated to each zone, n.

4.2.2 Constraints

A detailed description of all equations and constraints of the model is available in (Quoilin et al. 2017). The main model features and constraints can however be summarised by:

- Minimum and maximum power for each unit
- Power plant ramping limits
- Reserves up and down
- Minimum up/down times
- Load shedding
- Curtailment
- Pumped-hydro, battery and thermal storage
- Non-dispatchable units (e.g. wind turbines, run-of-river, etc.)
- Start-up, ramping and no-load costs
- Multi-nodes with capacity constraints on the lines (congestion)
- Constraints on the targets for renewables and/or CO2 emissions
- CHP min/max power and heat outputs
- Yearly schedules for the outages (forced and planned) of each unit.

4.2.3 Inputs and parameters

The main model inputs are the load and the variable renewable energy (VRE) generation curves. The model can indifferently operate with two different approaches: integrating the VRE into a residual load curve or considering VRE as power plants with must run constraints.

Since this model focuses on the available technical flexibility and not on accurate market modelling, it is run using the measured historical data, and not the day-ahead forecasted load and VRE production. This can be partly justified by the fact that a fraction of the forecast errors can be solved on the intra-day market. This perfect foresight hypothesis is however optimistic, and a more detailed stochastic simulation should be performed to refine the results.

Power plant data includes min/max capacity, ramping rates, min up/down times, start-up times, efficiency, variable cost (fuel prices are historical fuel prices for the considered period). It is worthwhile to note that some of the units such as the turbojets present a low capacity and/or high flexibility, such as the turbojets whose output power does not exceed a few MW, and which can reach full power in less than 15 minutes. For these units, a unit commitment model with a time step of one hour is unnecessary and computationally inefficient. Therefore, these units are clustered into one single, highly flexible unit with averaged characteristics.

5 Results and Discussion

In this section the comparison of different scenarios for the two pathways examined is presented and discussed. Due to the complexity when comparing two different sector coupling strategies (the electrification of the heating sector and the combined utilisation of cogeneration with district heating) aggregated indicators are used:

- Costs (power and heating sector). Power system costs include variable (fuel) and fixed costs as well as startup and shutdown costs and load shedding costs. Heating costs included the cost of fuel.
- Emissions (power and heating sector)
- Efficiency (power and heating sector)
- Ability to serve energy (power sector)
- Supply-side flexibility utilization (power sector)
- Interconnections congestion (power sector)

Beyond these global indicators, specific aspects from the different scenarios are presented to improve the understanding and implications among variables and assumptions.

Measuring supply-side flexibility

Flexibility definition and assessment in the context of a power system with high level of renewables has always been a topic of debate (Cruz et al. 2018; Lund et al. 2015). In this study we define flexibility in a broader context as the ability of the power system to react and absorb surplus or deficits of energy supply. Flexibility measures on the supply side, which are not related to the ramping capacity of the generation units, can fall into three major categories:

- Transferring energy in time: Storage
- Transferring energy in space: Interconnectors
- Wasting energy: curtailment

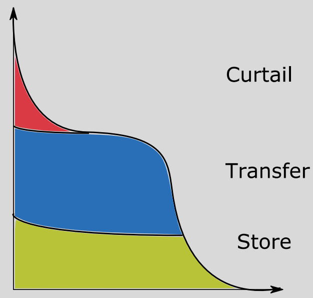

Figure 50. Conceptual merit order of flexibility represented as duration curve

Plotting the above three in the form of load duration curves, we can visualise a “merit order” of flexibility. This visualisation allows us to explore the duration (utilisation), the peak size and the amount of missing flexibility in the form of curtailment.

This plot assumes that all demand side flexibility measures such as (transforming energy to other carriers e.g. power to heat or demand response) are already included in the demand curve. This plot will be used in this study to assess the simulation results.

5.1 Heat electrification scenarios

The results of the power system simulations are presented in the following sections. While we we present aggregated indicators for different electrification rates, we focus mostly on the scenario where all fossil fuelled solutions are replaced with heat pumps, i.e. EL100 scenario.

5.1.1 Electrification based on today's power system

Energy not served

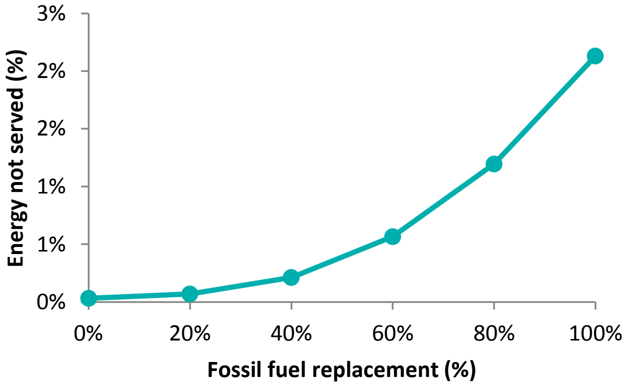

Figure 51. Results of scenarios EL20 to EL100

Figure 51 shows the energy not served for the degrees of fossil fuel substitution.

Figure 52 displays the number of hours during which the demand for electricity cannot be satisfied by firm capacities and Figure 53 the corresponding amount of energy, both on a member state level. It shows that even in the BLS scenario, this is the case for some country, stressing that a certain amount can be balanced by other flexibilities in the system, such as available renewable capacities or unused capacities in neighbouring Member States and might indicate that these countries have a positive import balance already today. It is therefore not a hard criterion of system failure as is the loss of load expectation. Nevertheless, it indicates which countries are better prepared for electrification, and in which countries electrification might risk the system's stability.

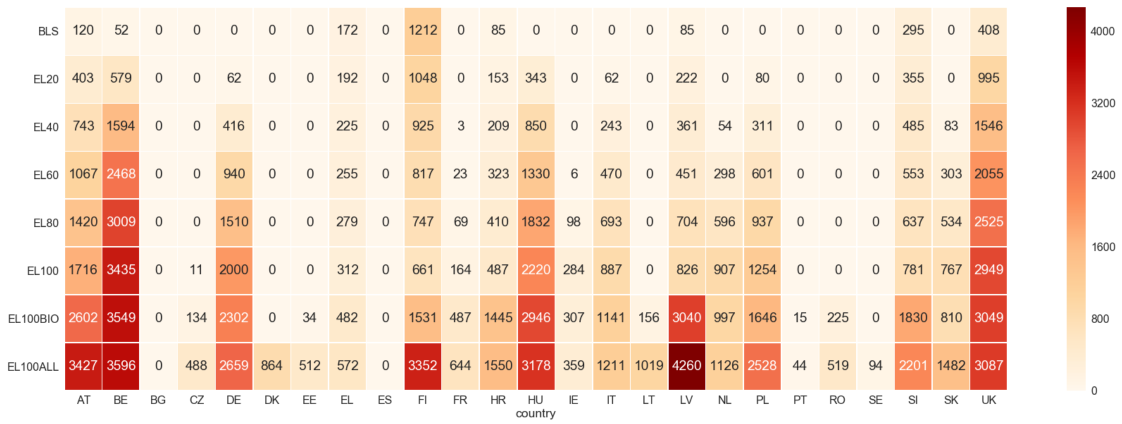

Figure 52. Number of hours during which the demand for electricity exceeds the firm capacity level, per Member State and scenario. Luxembourg excluded due to its strong import dependency, which results in load always exceeding the firm capacities.

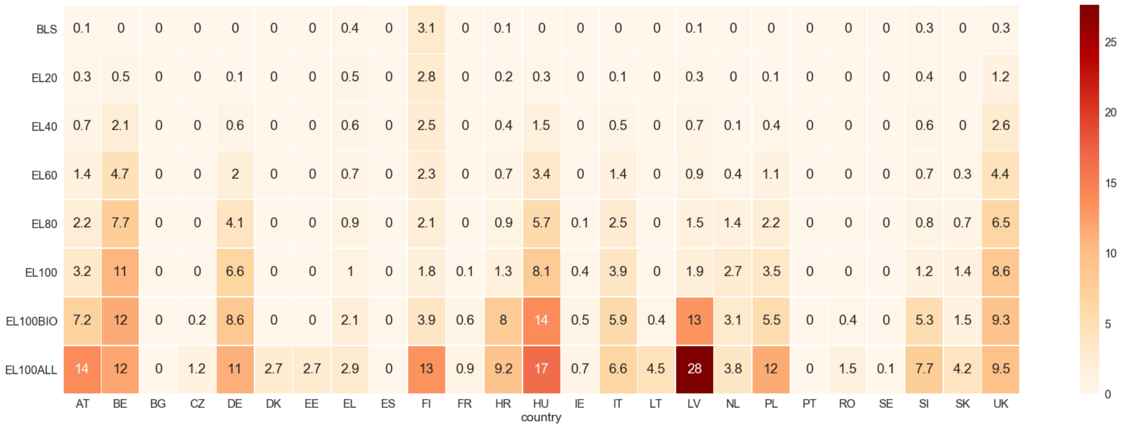

Figure 53. Percentage of annual demand exceeding the firm capacities, per Member State and scenario. Luxembourg excluded due to its strong import dependency.

It catches the eye that a group of eleven Member States seem very well prepared for a high degree of electrification. In the EL100 scenario, these countries have no substantial amount of demand that exceeds the firm capacity level. And even in the EL100ALL scenario, the number of hours is mostly below 1 000 hours and 3% of demand, numbers already exceeded by Finland in the BLS scenario. Striking is the regional composition of this electrification-ready group: While there are countries that profit from a warmer climate, such as Spain, Portugal, Romania and Bulgaria, there is a second group that consists of Scandinavian and Baltic countries, which stand out due to a much colder climate. The low impact that electrification has on Sweden, Denmark, Estonia and Lithuania (and also the Czech Republic) is due to the fact that their heating system already consists of a large share of low-carbon heating technologies.

In a second group of Member States, electrification takes a much larger toll on the system. In Belgium and the United Kingdom, the E100 scenario results an electricity demand which cannot be covered by firm capacities is around 10% and incurs over a cumulated timespan of more than four months, which is equivalent to the major part of the heating season. The numbers for Germany (6.6%) and Hungary (8.1%) are a little less severe, yet still imply two to three months cumulatively, which are not covered by firm capacities. These countries should closely monitor the progress of electrification and react to anticipated demand growth early through capacity investments in case of shortfalls threatening.

A third group of countries, consisting mainly of eastern European countries deal fairly well with the electrification of their fossil heating stock. As soon as biomass boilers get substituted, however, uncovered demand surges to 13% in Latvia (from 1.9% in the E100 scenario) and 8.0% in Croatia (from 1.3%). Similar effects, although less in magnitude, can be seen in Slovenia and Austria. For these countries, the major risk is the rising of biomass prices due to competition from other sectors, which would push their customers towards electric heating solutions.

Countries in the first group could even afford to completely electrify their heat sector. Smaller capacity additions would be necessary in some cases, when approaching complete electrification, which would most likely not be achieved within the near future. Countries in the second or third group should, however, only focus on replacing fossil driven boilers. Complete electrification would put an extreme burden on their power system. Only if heat demand is reduced or additional power generation capacities are installed further electrification should be targeted.

Overall, an electrification rate of 32%, which corresponds to the E60 scenario seems to be achievable on a EU28 level. Most countries would have fewer hours with demand exceeding the firm capacities, as well as less associated energy, than Finland does already today. Critical countries would be the United Kingdom and Belgium, as well as Hungary to a lesser degree.

A rapid electrification according to the EL100 scenario would put a lot of stress on the European power system leading to a 2.90% of the total load not being served. The picture at individual member state is even more severe, with almost 20% of load being shed in the United Kingdom and more than 10% of load losses in Italy, Hungary, the Netherlands, Belgium and Slovenia.

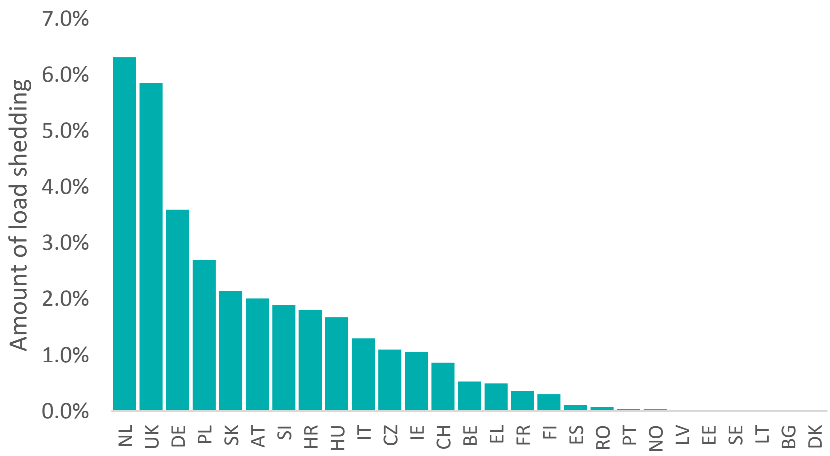

Figure 54. Percentage of energy not served in the EL100 scenario

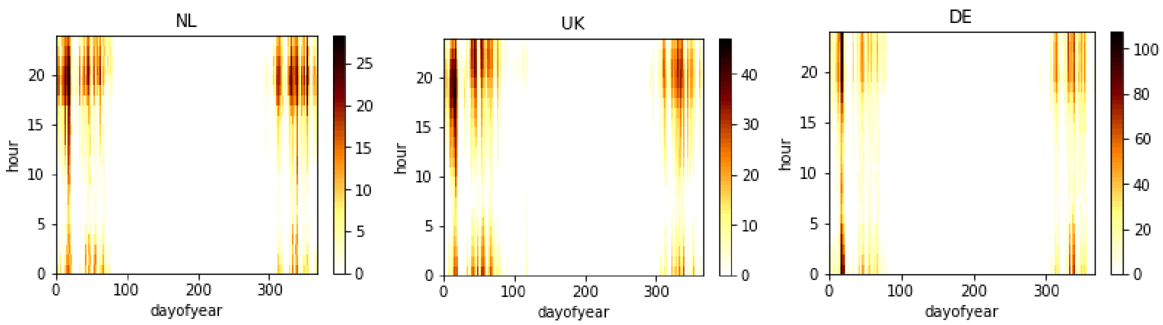

Figure 55. Unserved energy per day of year and hour of day for countries that are affected the most (TWh)

On the other hand, countries in the north and/or the east of the EU appear quite resilient against a sudden rise in electrification. The decisive factor does not seem to be the climatic location of the MS, but much rather its pre-electrification share of decentralised heating applications. Therefore, we see the greatest amount of lost load in central Europe, which today has a strong reliance on gas boilers for residential heating.

Operating Costs

The operating costs in the power sector increase more than double due to electrification, from EUR 31 billion in the BLS scenario to EUR 66 billion in the E100 scenario[5]. Since all heating services are provided either through CHP plants or heat pumps, no additional operating costs are accounted for the heating sector (compared to EUR 69 billion in BLS2015). This means that even though costs in the power sector rise, there is an overall annual cost saving of 34 billion EUR.

Emissions

The climate change mitigation effect of heat electrification for the different scenarios is shown in Figure 56. The individual country results are affected by 3 factors: a) the current degree of electrification b) the current state of the power mix and c) the relation of heat demand to (non-heat related) power demand. All countries benefit from an emissions as well as an energy efficiency point of view for as long as only fossil fuelled boilers are being replaced. While the energy efficiency benefits further increase with additional electrification, emissions might even rise above the level in the BLS scenario, if the electricity mix has a high carbon intensity index. This is most notably the case for the Baltic States and Denmark.

[5]This excludes the penalty implied by the energy that was not able to be served

The member state profiting most from electrification is France with a 65% reduction in CO_2-emissions in the EL100 and EL100BIO scenarios. On one hand, France's electricity sector is largely based on nuclear power plants and has therefore very low carbon intensity. On the other hand, the French heating sector still consists of 55% gas and oil boilers.

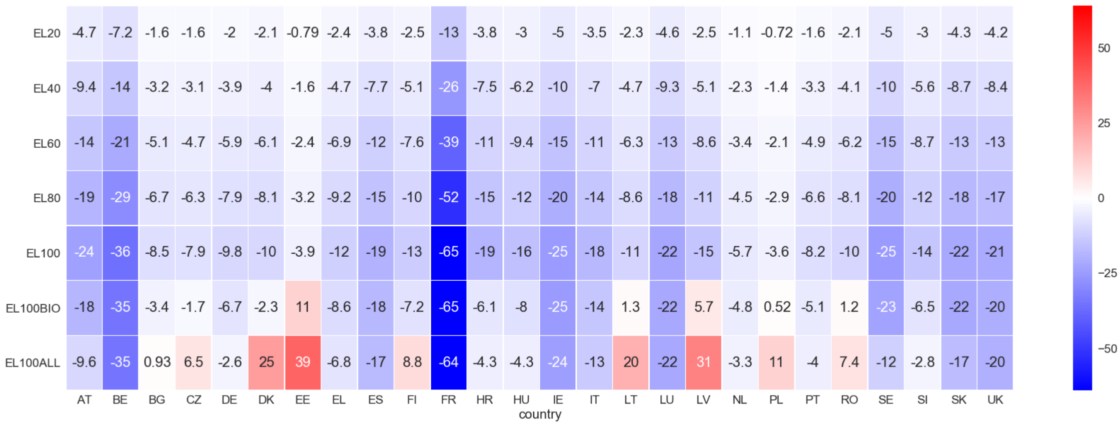

Figure 56. Change in CO2-emissions (%) in the power and the heat sector combined in the different electrification scenarios compared to BLS

Generation mix

The amount of generation (peak and total) per technology is presented in Figure 57 in the form of load duration curves. As the power capacity between the two simulation is the same, the only generation units that are able to provide the additional power needed are the dispatchable and flexible generation technologies, i.e. gas and coal fired. The area between the two lines expresses the additional energy provided.

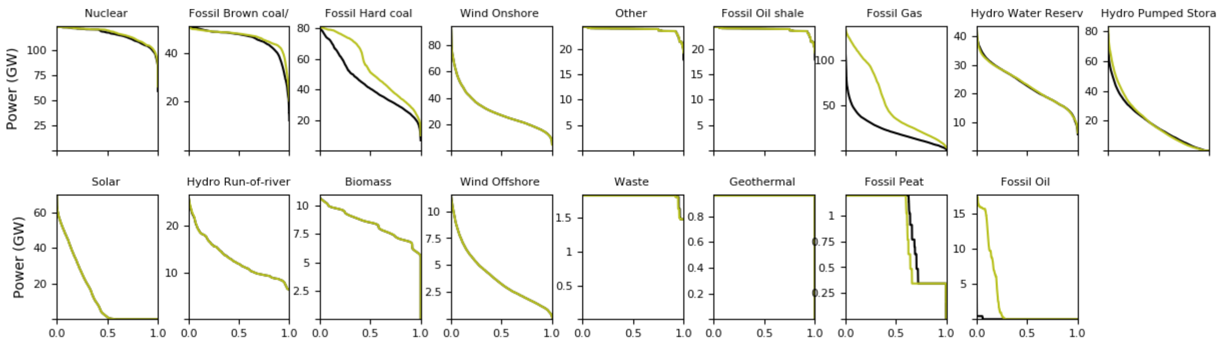

Figure 57. Power plant generation per technology for the base (BLS2015) in black and the full electrification scenario (E100) in green

Supply–side flexibility

In the current system flexibility needs are mostly covered by interconnections (green area). Approximately 60GW of electricity are transferred out at any given hour. In the case of storage there is use of a 20GW of storage capacity but only for 10% of the year (Figure 58 and Figure 59).

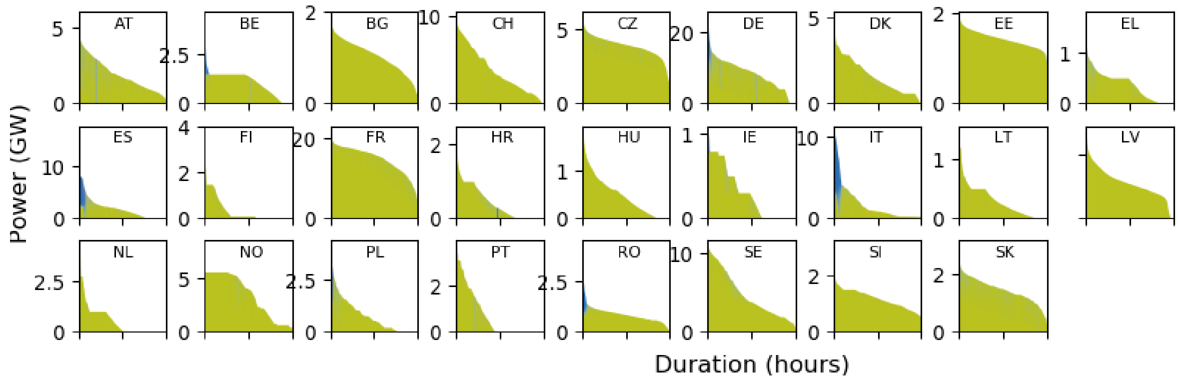

Figure 58. Flexibility needs in the form of a load duration curve for E100. Colour coding: Green (outflows) blue (storage), red(curtailment)

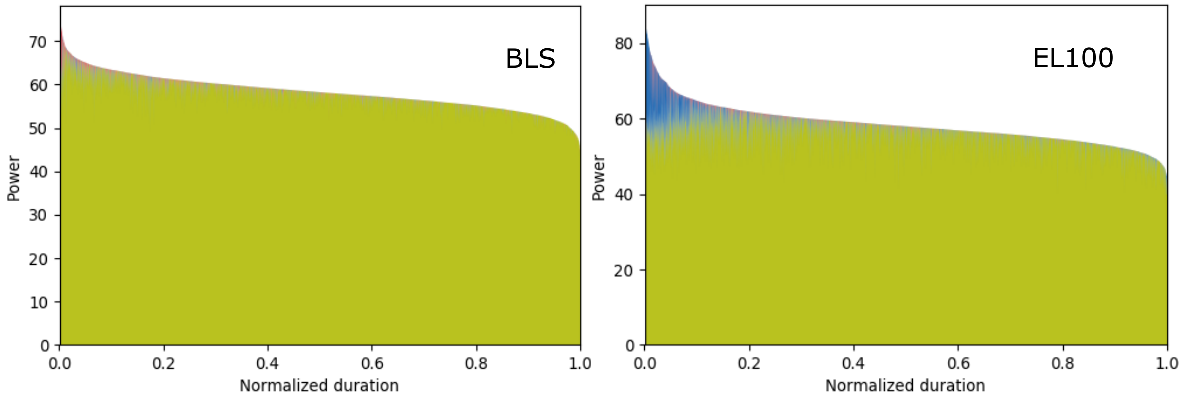

Figure 59. Aggregated flexibility needs (GW) in the form of a load duration curve for (left) BLS (right) E100. Colour coding: Green (outflows) blue (storage), red (curtailment)

One more indicator for more flexible thermal power plants is the amount of times that they need to cycle. We observe that there is a need for more flexible power plants. The higher the electrification rate the higher the number of startups (Figure 60).

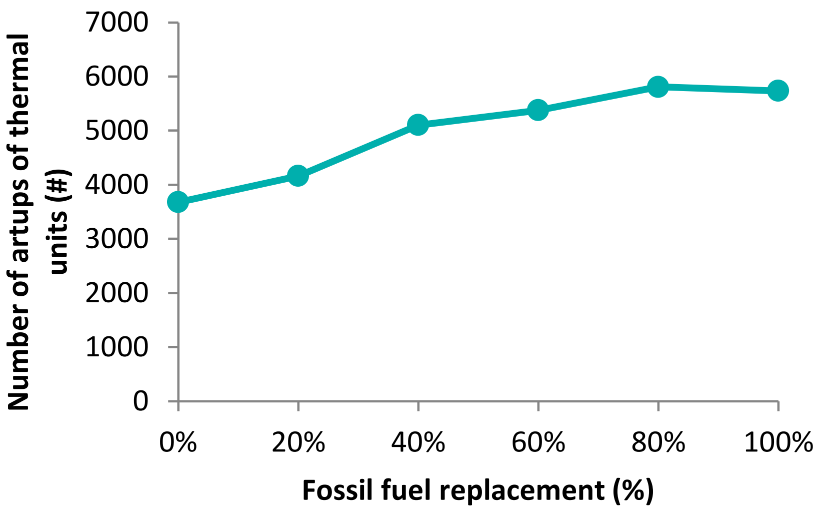

Figure 60. Startups of scenarios EL20 to EL100

Interconnection congestion

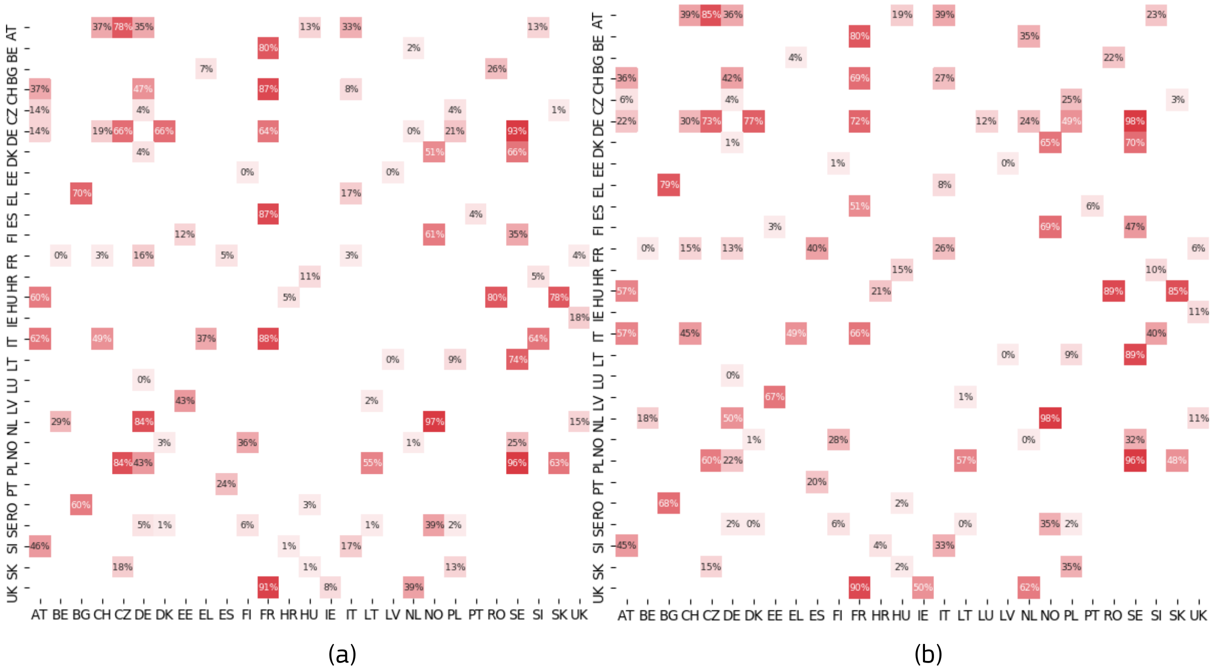

Figure 61. Interconnections for (a) BLS and (b) E100

The matrix of Figure 61 shows the percentage of the hours that any given interconnection between two countries is congested, i.e. operating at full capacity. France and Sweden have the most congested interconnections mainly because of their ability to serve energy to nearby countries when residual load is high. This is caused mainly by their high firm capacity (nuclear and hydro storage). This changes with an electrification scenario as the overall interconnection utilisation is rising as the system is trying to utilise any source of flexibility.

5.1.2 Electrification scenarios for a future power system (2050)

Energy not served

Energy not served in the EL100_2050 scenario is smaller than in the EL100 one due to the lower amount of heat demand and the higher capacities. In general, it amounts to 1.2%, and is almost 0% for more than half of the simulated countries. Higher amounts of load shedding still occur in central and eastern European countries, though it halves in many cases, compared to the E100 scenario. This reduction of lost load is mainly due to the assumed improvements in buildings efficiency, which result in a lower electricity demand.

A full electrification scenario therefore seems much more realistic in the 2050 perspective, although a further development of the power sector would still be necessary in some countries to be able to deal with the additional stress.

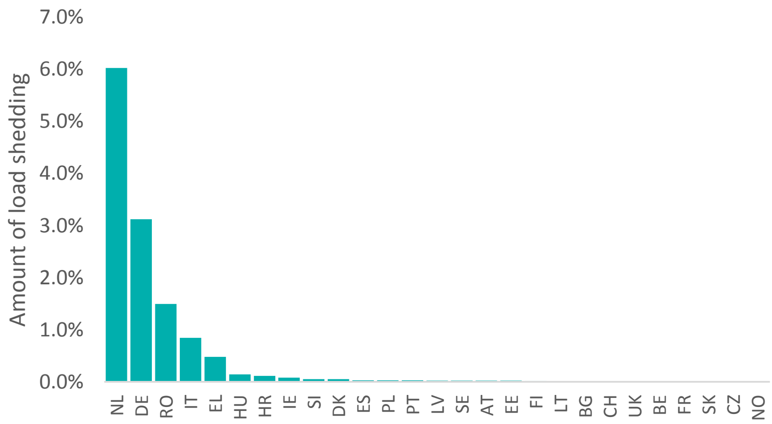

Figure 62. Proportion of energy not served in a future electrification scenario

Interconnection congestion

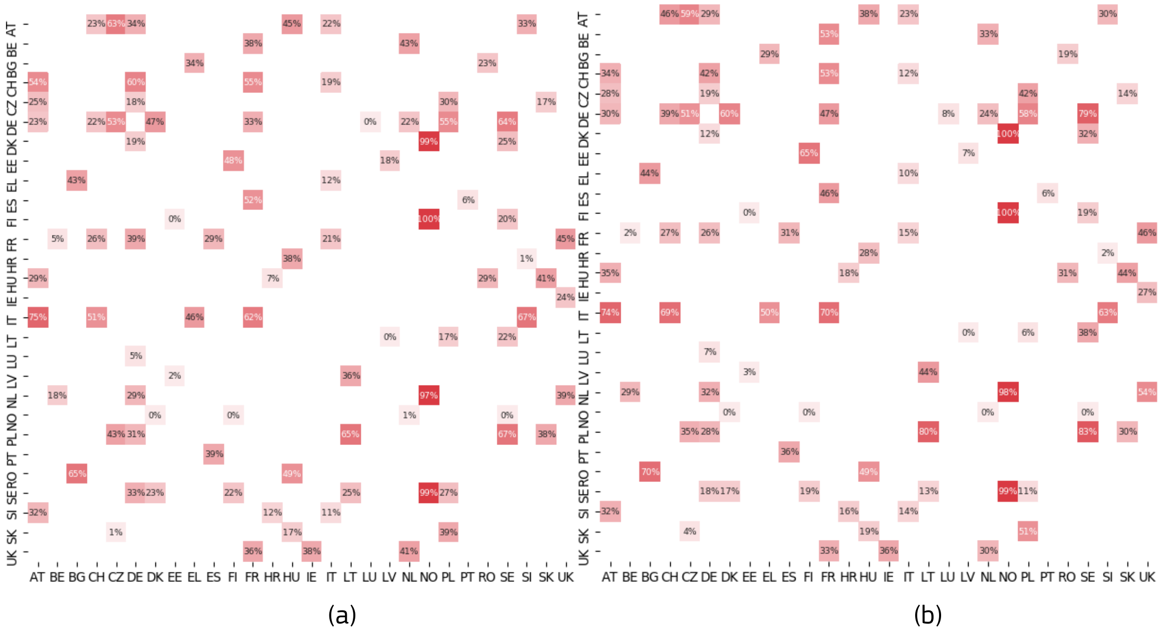

Figure 63. Interconnections among different countries for the case of 2050 (a) BLS (b) E100. The percentage shows the amount of hours that a specific interconnector is congested

Like in the case of 2015, overall interconnection utilisation is also rising as the system is trying to utilise any source of flexibility.

Operating costs

Similarly, as in the case of 2016, the full electrification scenario brings down the total operating costs (excluding load shedding costs). In the BLS scenario, the operation of the power sector costs EUR 42 billion yearly, while fuel costs in the heating sector amount to EUR 29 billion. Total operating costs in the E100BIO_2050 drop from 71 to 66 (in EUR billion), which all accrue in the power sector.

Emissions

In this case, the base case consists of a semi-decarbonized power system with emissions of about 136 MtnCO_2 and a heat sector with emissions of 328 MtnCO_2. The electrification case (EL100) results to combined emissions of 280 MtnCO_2 which corresponds to an achieved overall reduction of 25%.

Generation mix

Similar to 2016 we observe that fossil fuelled generation increases in order to deal with the increased demand. This justifies what is observed in the emissions. Moreover, it is clear that a lot of curves are reaching close to saturation point due to the lack of adequate spare firm capacity which is why there is also a small amount of lost load.

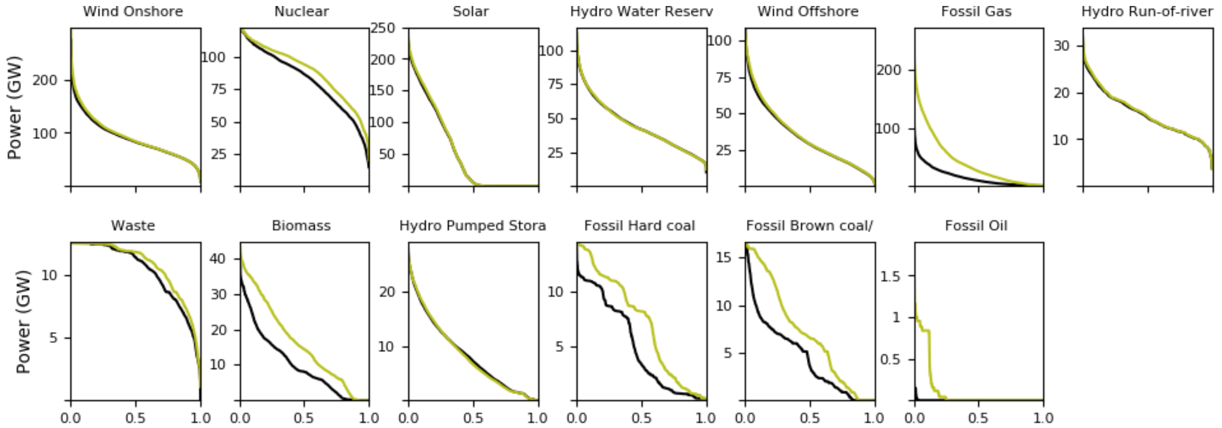

Figure 64. Power plant generation per technology for the base (BLS2050) and the full electrification case (FES2050)

Supply–side flexibility

In the future power system scenario system flexibility needs are mostly covered by interconnections as can be seen in Figure 65 - Figure 66 (green area) but in this case there is significant amount of curtailment (red area). As the same amount of interconnection capacity was assumed the total amount of power transferred is similar (green area). The amount of peaks in the demand and curtailment is increasing. In the case of electrification EL100 case the heat demand is able to absorb 17% of the curtailed energy. i.e. from 263 TWh to 218 TWh.

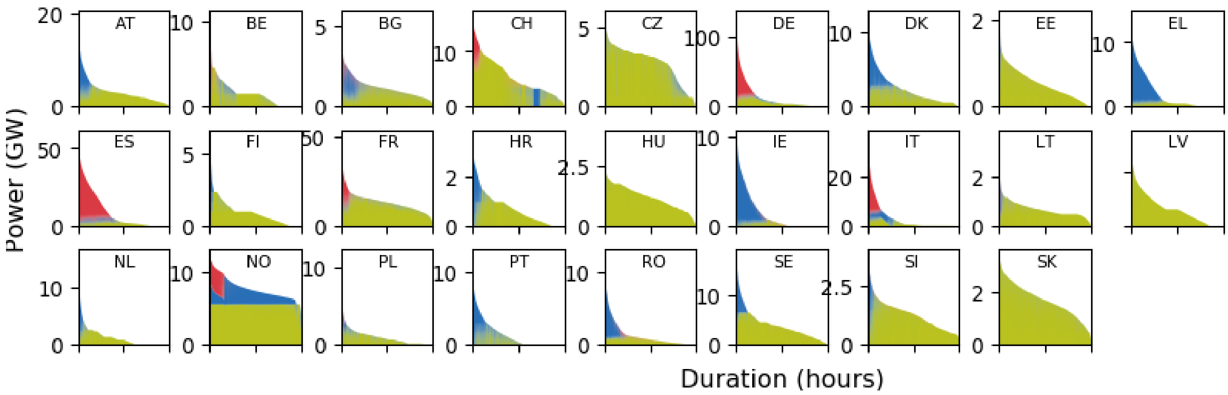

Figure 65. Flexibility needs in the form of a load duration curve for E100 2050 scenario. Colour coding: Green (outflows) blue (storage), red (curtailment)

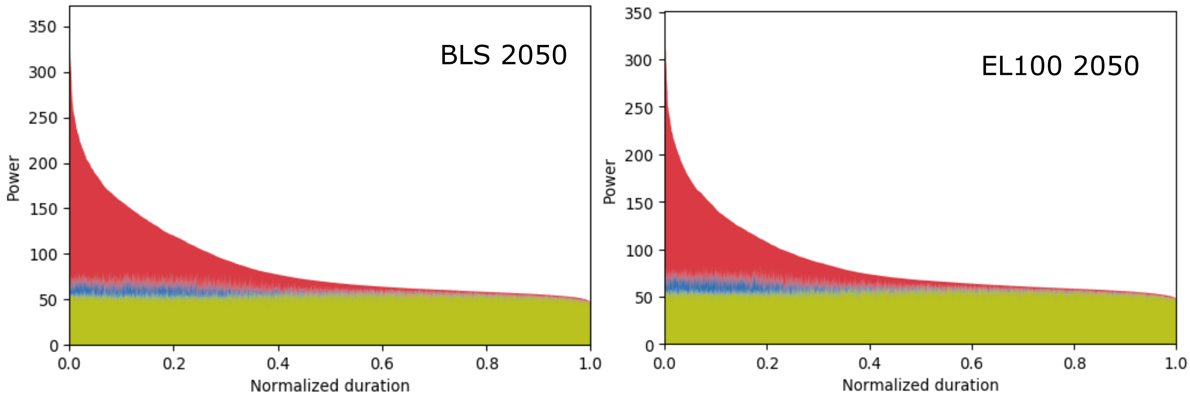

Figure 66. Aggregated flexibility needs in the form of a load duration curve for (left) BLS 2050 (right) EL100 2050. Colour coding: Green (outflows) blue (storage), red (curtailment)

5.1.3 Summary of results and sensitivity analysis

Sensitivity analyses were conducted in some runs in order to assess how the system behaves with different parameters. More specifically, the value of flexibility that the heat sector could offer is presented by creating a load curve where 6% of the highest peaks during a month would be transferred to off peak times. Moreover, a doubling of interconnections and/or renewable capacity (RES) is examined. The complete table of the sensitivities runs is shown below for the 2015 (Table 5) and 2016 case. The first columns show the definition of the simulations, i.e the sensitity of each variable in the form of a factor compared to the base case. The first columns correspond to the multipliers of different parameters (e.g. 2 means that interconnection capacity is doubled). Scenario names ending with *DR* correspond to a load shifting case.

Table 5. Sensitivity analysis (2015)

Base demand scenario	Interconnection multiplier	Solar multiplier	Wind multiplier	Storage multiplier	Congestion (Average hours)	Curtailment (TWh)	Peak load (GW)	Number of thermal startups	Lost load (%)	Power system emissions (Mtn CO_2)
BLS	0	0	0	0	31.0	2.0	812.4	5736	0%	1029
BLS	1	1	1	1	30.4	1.9	554.2	3677	0%	817
BLS	2	1	1	1	24.9	0.9	554.2	3017	0%	1047
EL20	1	1	1	1	30.3	1.9	605.9	4163	0%	812
EL40	1	1	1	1	30.4	2.0	657.4	5101	0%	869
EL60	1	1	1	1	30.5	1.9	709.0	5378	1%	917
EL60DR	1	1	1	1	30.5	2.1	628.6	6335	0%	1001
EL80	1	1	1	1	30.7	1.9	760.7	5807	1%	960
EL80DR	1	1	1	1	30.8	2.1	666.5	6574	1%	961
EL100	1	2	1	1	30.8	3.7	812.4	6851	2%	880
EL100	1	1	2	1	31.1	8.9	812.4	6998	1%	1084
EL100	1	2	2	1	33.9	59.3	812.4	6318	1%	742
EL100	1	1	1	1	31.0	2.0	812.4	5736	2%	998
EL100DR	1	1	1	1	30.9	2.0	709.5	6410	1%	1029
EL100	2	1	1	1	25.8	0.8	812.4	5415	2%	1038
EL100	2	2	2	1	25.9	8.0	812.4	7493	1%	783
EL100	3	1	1	1	24.1	0.3	812.4	5033	1%	1052

Table 6. Sensitivity analysis (2050)

Base demand scenario	Interconnection multiplier	Solar multiplier	Wind multiplier	Storage multiplier	Congestion (Average hours)	Curtailment (TWh)	Peak load (GW)	Number of thermal startups	Lost load (%)	Power system emissions (Mtn CO_2)
BLS	1	1	1	1	32.3	263.6	554.2	11028	0%	112
BLS	2	1	1	1	28.0	210.7	554.2	8795	0%	136
BLS	2	1	1	1	28.0	210.7	554.2	8795	0%	164
EL20	1	1	1	1	32.2	251.4	605.9	11762	0%	194
EL40	1	1	1	1	32.2	241.8	657.4	12216	0%	228
EL60	1	1	1	1	32.3	233.1	709.0	12677	0%	223
EL60DR	1	1	1	1	32.3	206.2	628.6	12775	0%	258
EL80	1	1	1	1	32.5	224.9	760.7	13024	1%	252
EL80DR	1	1	1	1	32.4	196.7	666.5	12951	0%	103
EL100	1	1	1	1	32.5	218.6	812.4	13744	1%	252
EL100	1	2	1	1	33.3	629.2	812.4	15649	1%	280
EL100	1	2	2	2	36.8	1356.7	812.4	7420	0%	247
EL100	1	1	2	1	34.3	817.8	812.4	10327	0%	289
EL100DR	1	1	1	1	32.5	188.0	709.5	13924	0%	262
EL100	2	2	2	1	31.3	1212.6	812.4	8896	0%	102
EL100	2	1	1	1	28.1	172.5	812.4	12140	0%	147
EL100	3	1	1	1	25.6	146.0	812.4	10394	0%	112

Load shifting leads to a decrease in unserved energy down to 1.1%. Additional demand can be covered, since it was shifted to off-peak times, when there are still capacities available (Figure 68)

Combining the investigated measures further improves the results with regard to all indicators. RES scenarios push down load shedding, emissions and operating costs the most, however increase in curtailment rates of more than 20% are observed. Load shifting is not enough when there are capacity adequacy problems. Out of the three options, however, load shifting appears to be the one associated with the smallest amount of capital cost, since additional storage or generation capacity tends to be more cost intensive.

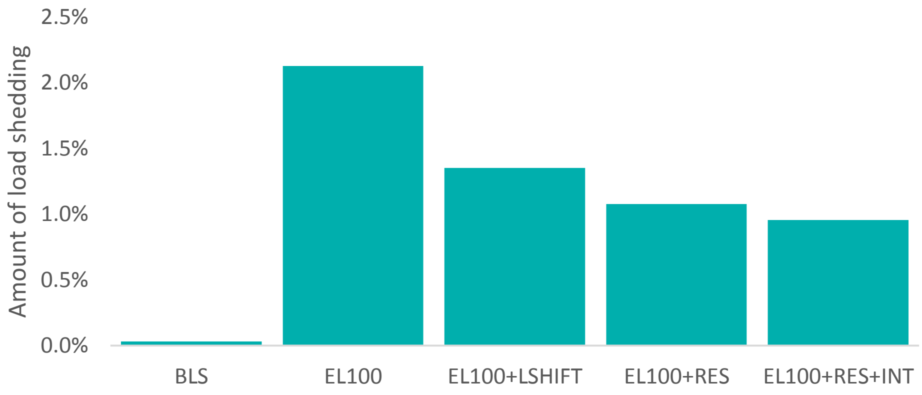

Figure 67. Load shedding sensitivity to additional renewable generation, interconnections and load shifting in the EL100 scenario

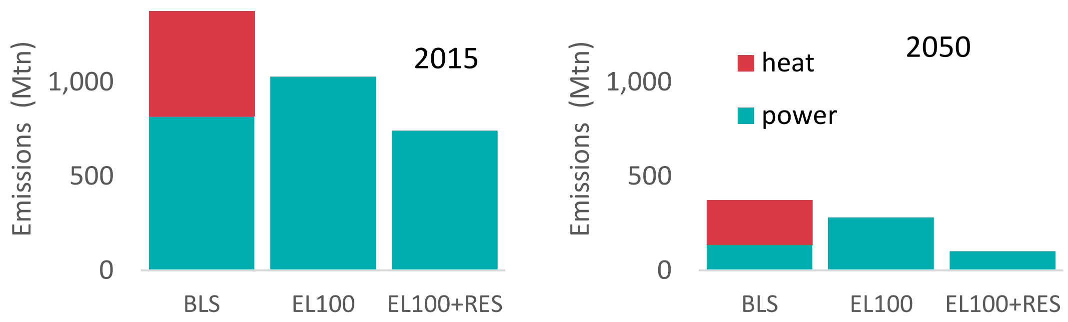

Figure 68. Greenhouse gas emissions sensitivity to additional renewable generation in the El100 scenario for current and future power and heat sector.

Figure 69 shows how the combined emissions of heat and power drop in the electrification scenario and with a doubling on the renewable capacity. This is the expected behaviour, however they do not drop as much as expected as the additional energy needed for the heat sector cannot be provided by the same mix but by the dispatchable technologies which have usually higher emission rates that the average mix.

5.2 Cogeneration and district heating scenarios

The use of centralised cogeneration plants in combination with district heating results in a shift from fossil fuels to district heating as described in previous sections (Figure 45). The new combined heat and power capacity enables a highly efficient and more affordable energy generation compared with the original fossil fuelled options, e.g. power plant and boiler. As a result, the CHP plants operate at high capacity ranges.

As a consequence, the CHP plants operating at high capacity factors increase the shares of renewable generation that are curtailed especially when large amounts of heat can be supplied. This happens because it is more cost-effective to deliver heat and power simultaneously and curtail renewable production than delivering heat from alternative sources. In annex 6, an example of a weekly dispatch can be found for different scenarios CHP and thermal storage scenarios. Detailed information on the impact of cogeneration on the curtailed energy follows in the next section.

Looking into 2050, the higher shares of renewable energy result in a lower contribution from the CHP plants. If we compare both years for the full potential scenario including storage, the CHP contribution falls from 28% to 21% while the renewable share increases from 11% to 37%. Therefore, the increase in the renewable capacity is decreasing the utilisation of centralised heat from CHP plants and vice versa (

Figure 69).

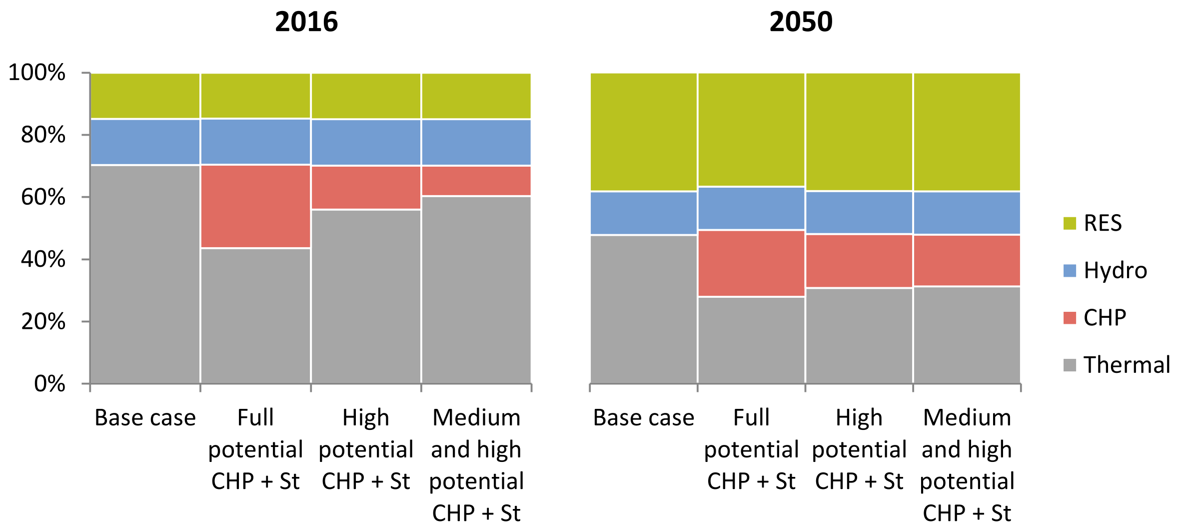

Figure 69. Share of electricity generation per group of energy generation technologies[6]

Curtailment

As indicated before, the deployment of RES impedes a large utilisation of CHP plants. Still, the heating demand has to be covered in a cost-effective way. This means that there is a trade-off between RES and CHP utilisation. The optimal mix of supply is determined by the efficiencies and costs of the supply-side heating technologies. Therefore, the system has two possibilities; either it curtails RES power or it limits the utilisation of the available CHP capacity and increases the utilisation of the alternative heat supply.

In the current scenario, curtailed RES generation represents less than 1% of the useful RES generation while for the full potential conversion scenarios it increases to 9%. In 2050, the same pattern is observed but at higher values due to the fact that a large RES installed capacity is predicted. As a result, for the same scenarios, the curtailed RES generation increases from 6% to 11%. It is also observed for both years that the amount of curtailed power decreases when the feasible heat demand density levels are limited to a certain amount of TWh per sq-km. A low available heat demand to be supplied by centralised CHP plants reduces their operation and larger amount of RES can be delivered (Figure 70).

[6] RES includes wind solar and bio, Thermal includes gas and steam turbines and combined cycles and, Hydro includes conventional hydro dam, hydro run-of-river and pumped hydro storage.

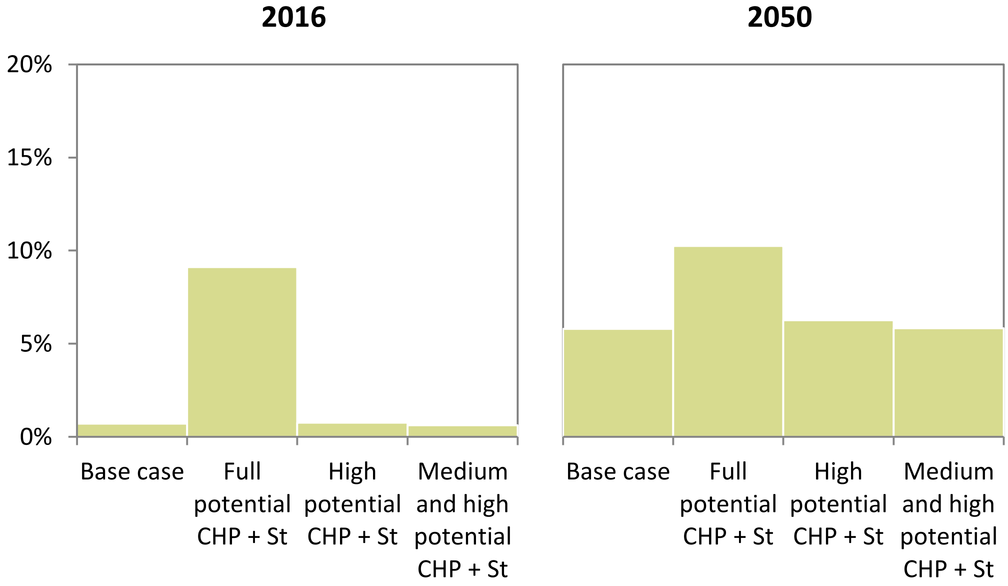

Figure 70. Share of curtailed energy from renewable sources

Heat generation

The heat supply from CHP varies depending on the available heat sinks in the different scenarios. The share of heat supplied from CHP plants represents more than half of the total heat demand — 58% of the total heat demand for the full potential scenario. This share decreases with the lower availability of high heat demand density areas, as described in section 1.1.1 (Figure 71). In 2050, the shares of heat supplied from CHP are even higher due to a lower heat demand (67% of 2016 heat demand). But, the gross amounts of heat produced by CHP decrease from 2016 to 2050 for the equivalent scenarios studied. In the full potential scenario, the reduction of the gross heat production is in the order of 20%. Therefore, the combined generation of heat and power is the preferable option as long as the cogenerated heat can be distributed by existing district heating networks.

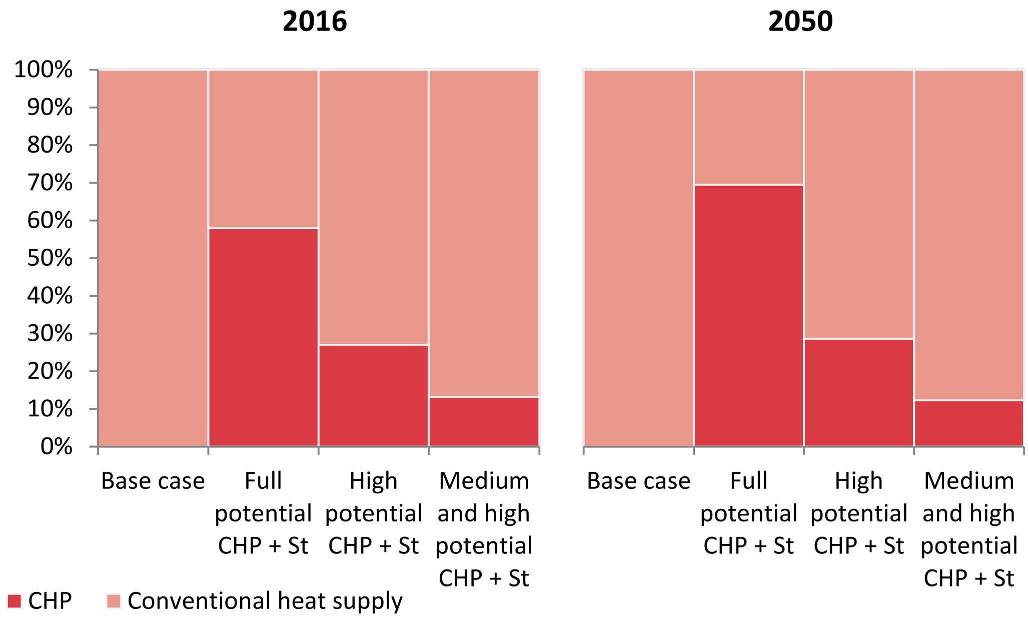

Figure 71. Share of heat generation

Operational costs

The conversion of centralised combined heat and power plants into combined heat and power plants reduces the total cost of the system. For both years under study, operating cost drops depending on the utilisation of CHP plants. The full potential scenarios cut down costs by 17% and 20% for 2016 and 2050 respectively. The increase in the power operational costs is due to the higher utilisation of the CHP capacity. In the case of 2016, the power operational costs increase by 48% (14% in 2050).

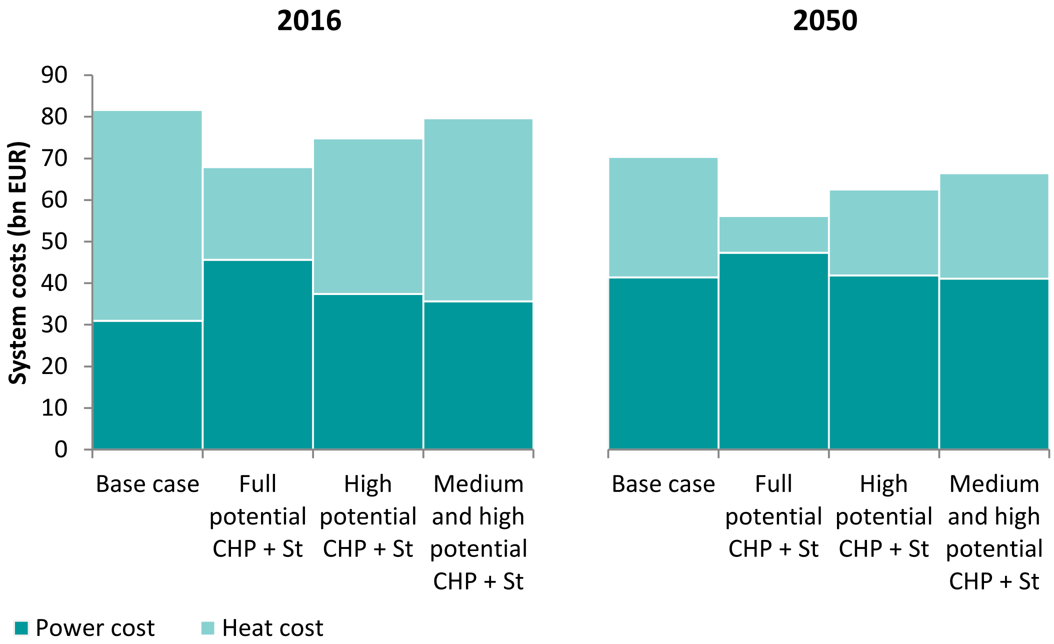

Figure 72. Total system costs

Overall system efficiency

One of the major benefits resulting from the use of centralised cogeneration and district heating is the increase in the overall efficiency of the system. The overall efficiency of the system is defined as the ratio between the total amount of useful energy delivered (heat and electricity) and the total input fuel. This increase is observed due to the high overall CHP efficiencies that for some operational ranges can reach values of 90%. At the same time, conventional thermal plant efficiencies are in the order of 50%.

The overall efficiency in the full potential scenario increases by 20% compared with the base case scenario in 2016 that increases from 63% to 76%. In 2050, due to the higher shares of renewables and thus less utilisation of CHP plants, the overall efficiency increases only by 10% (from 73% to 80%). In both years, a fall in the overall efficiency is observed in the scenarios that centralised heat can only be supplied in areas with certain levels of heat demand density.

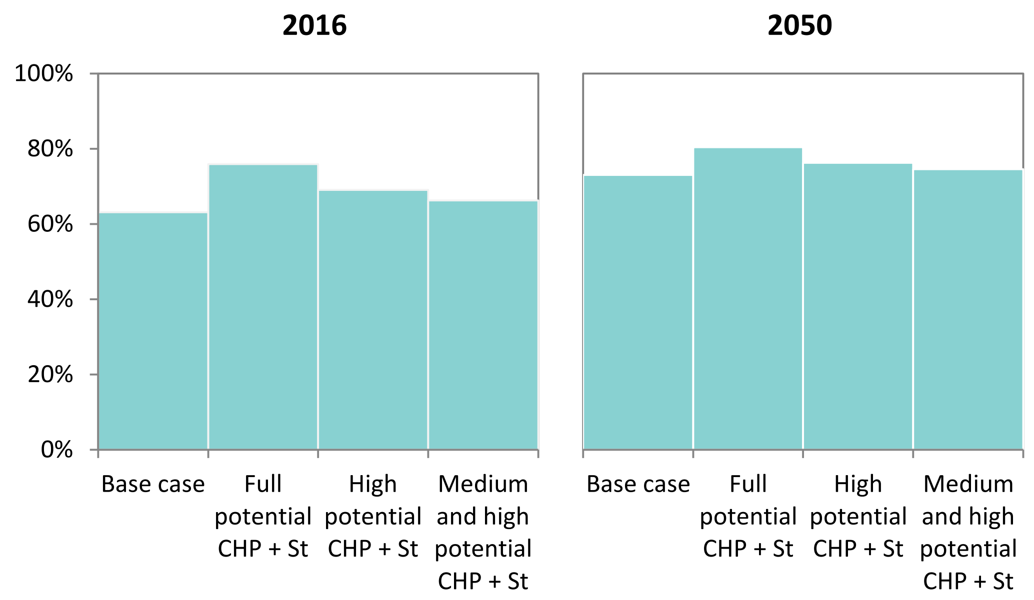

Figure 73. Total system efficiency

Emissions

CHP leads to a considerable reduction of CO2 emissions. For the 2016 scenarios the total CO2 emissions are reduced from 1 320 MtCO2 to 980 MtCO2 in the full potential scenario (24% reduction). CO2 emissions remain below the base case scenario even when the utilisation of centralised heat is limited to the high energy demand density areas. For those cases emissions are reduced by 4% in both year scenarios. For the 2050 scenario is observed an increase in the emissions compared with the base case scenario (+13%) as a result of a higher amount of renewable energy curtailed. This increase in the power system is compensated by a 70% CO2 emissions reduction achieved in the heating sector, leading to a global reduction of 17% (Figure 74).

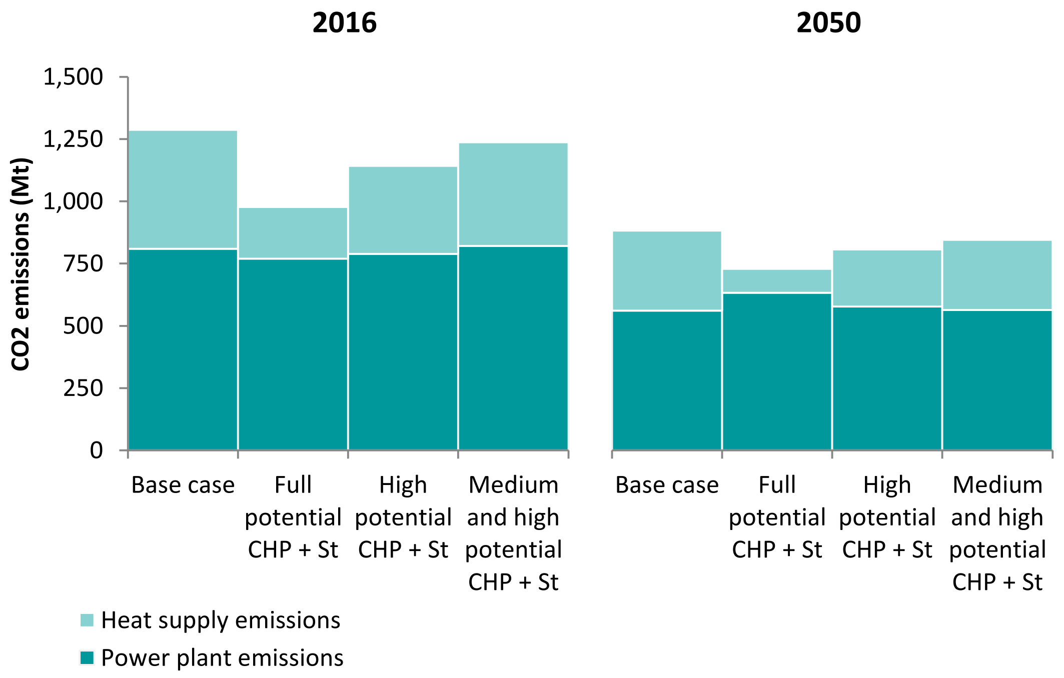

Figure 74. Total emissions (thousands of ktCO2-eq)

Generation mix

The analysis of the power generation per technology shows how the use of CHP plants that triple its production (fossil gas category) affects the contribution from the different technologies. As a result, power from coal, oil and waste decreases considerably both in 2016 and 2050. To a lesser extent, the use of CHP lowers the power generation from nuclear. Regarding renewable technologies, wind production remains the same for the scenarios under the same year while solar is reduced (Figure 75). The same effect is observed in 2050.

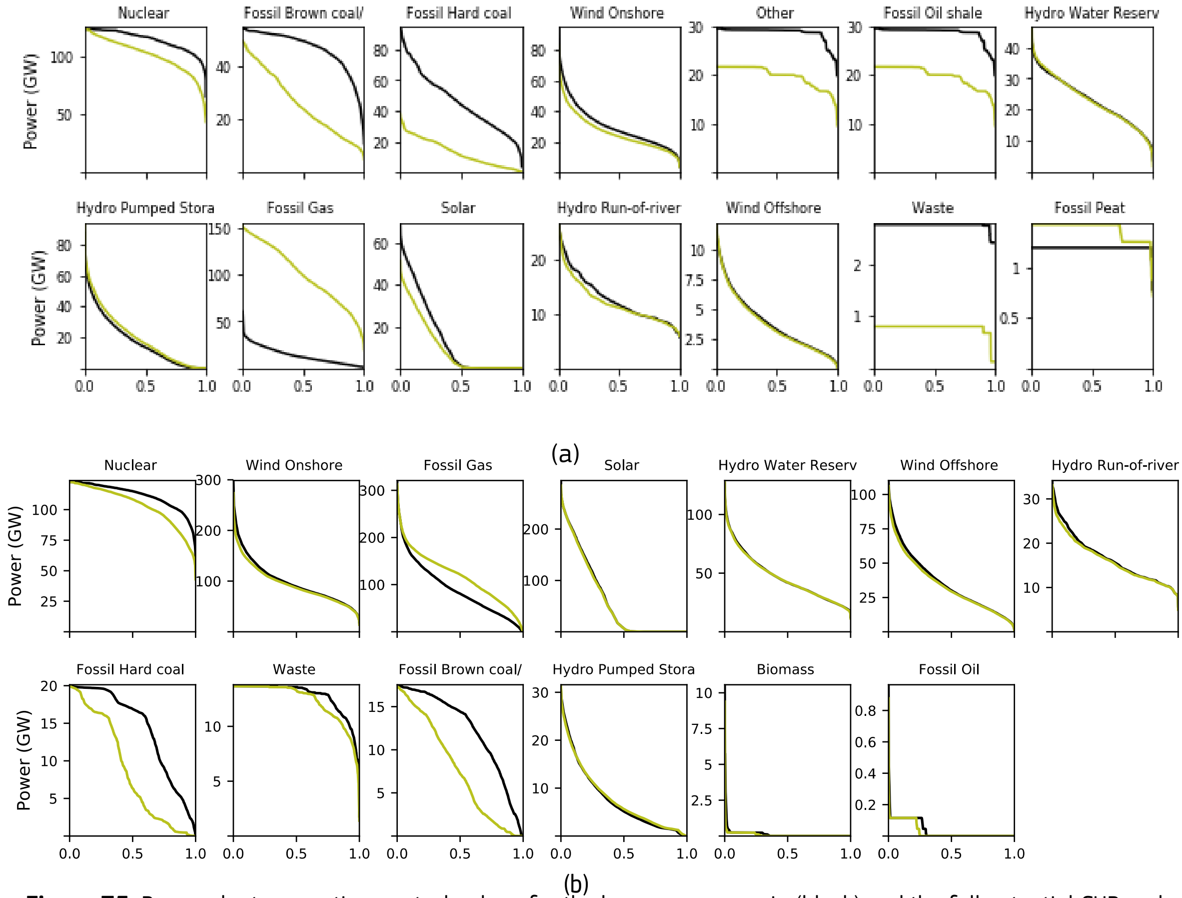

Figure 75. Power plant generation per technology for the base case scenario (black) and the full potential CHP and thermal storage (green) in the form of Load duration curves for (a) 2016 and (b) 2050

Figure 76 presents the annual generation per technology for all scenarios.

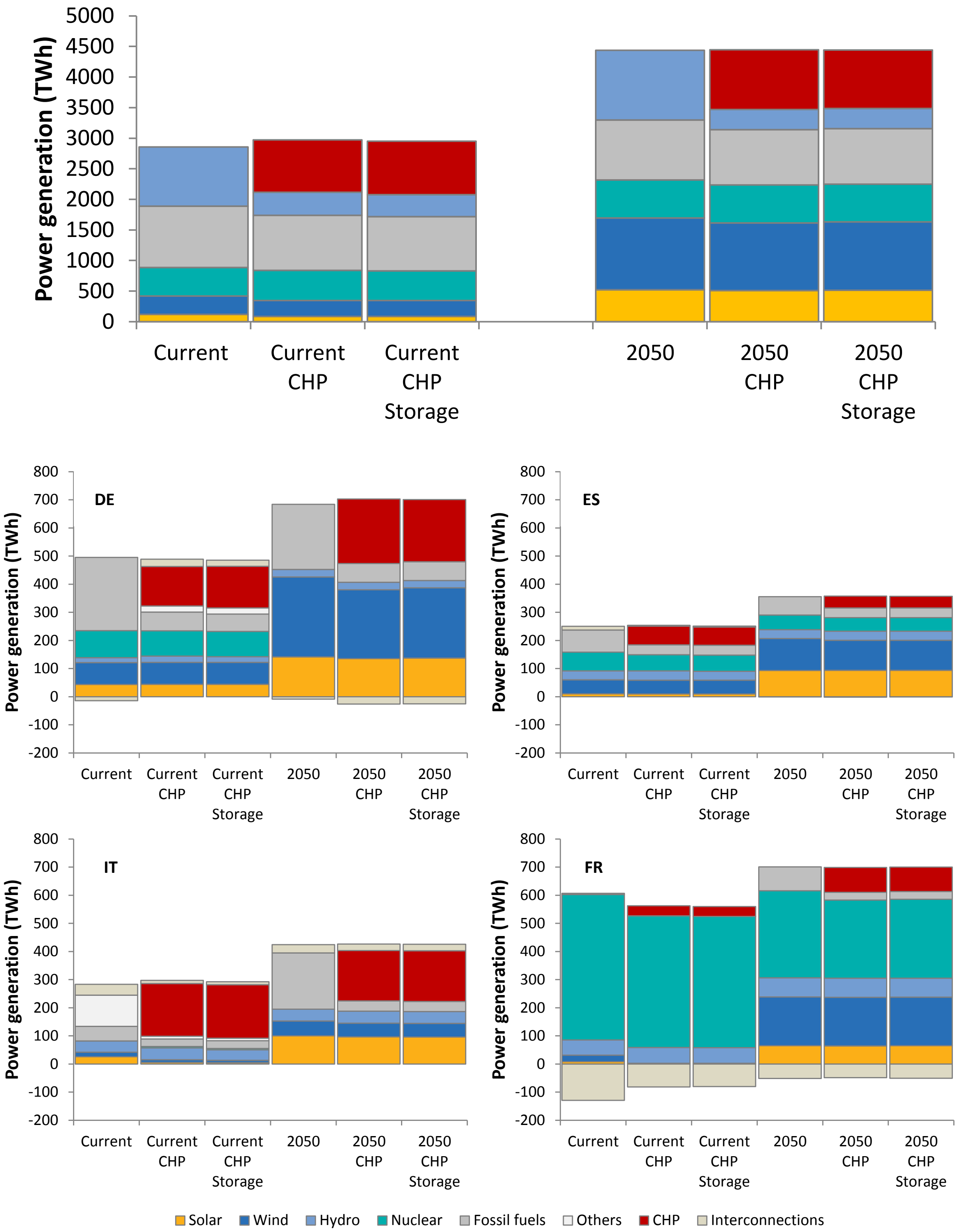

Figure 76. EU Power generation for different scenarios

A summary of metric for all scenarios can be found in Table 7:

Table 7. Power system metrics for different scenarios examined

Scenario	Context timeline	Load sheding (GWh)	Curtail (GWh)	Average Congestion (%)	Thermal startups (#)
Baseline		0.02	2.9	32.3	4539
CHP full potential		0.17	32.5	33.2	3320
CHP + Storage		0.17	31.6	33.8	2744
CHP high potential	Current	0.08	3.0	32.7	3564
CHP high potential + Storage		0.10	2.8	33.6	3567
CHP medium potential		0.09	2.7	33.1	3639
CHP medium potential + Storage		0.06	2.3	33.0	3431
Baseline		1.03	98.2	33.6	20,623
CHP full potential		0.72	182.6	34.6	16,201
CHP + Storage		0.70	167.2	35.0	17,022
CHP high potential	2050	0.87	120.6	34.2	17,590
CHP high potential + Storage		0.89	105.6	34.4	18,361
CHP medium potential		0.84	105.8	33.9	18,132
CHP medium potential + Storage		0.86	98.7	33.9	18,322

5.2.1 Evaluation of network investment costs

The estimation of costs has been done for the 14 EU countries included in the Heat Roadmap Europe project. They represent 85% of the total EU demand. As a result, the assessment provides valuable insights on the investments required to deploy thermal networks across Europe.

The evaluation of costs focuses on the piping costs, which represent the largest cost when it comes to deploying a thermal network. Thus, costs associated with the thermal stations have been neglected as well as the cost associated with the conversion of thermal power into cogeneration plants. The analysis does not consider existing thermal network. Consequently, in those countries with higher penetration of DH, costs are overestimated, especially for those. Still, aggregated investment values, presented for 14 EU countries, provide valuable insights on the potential of DH.

We follow the method provided in (Grosse et al. 2017) together with the geographical information available in PETA4 (Heat roadmap Europe project 2018). First, we have associated a building density value (e) to the four levels of demand included in PETA4.

Table 8. Estimation of building density per demand density

	Class 1	Class 2	Class 3	Class 4	Class 5
Heat demand density (TJ / km^2)	0 - 20	20 - 50	50 - 120	120 - 300	>300
Building density (m^2 gross floor area / m^2 land area)	0.15	0.25	0.3	0.45	0.6

Then, we calculate the weighted average building density ($\overline{e}$) based on the different demand levels in a given area. We continue with the calculation of the route meter per supplied land area (rm) in km rm / km2 land area based on the empirical equation provided in (U. Persson and S. Werner, 2011)

$$y = 16.171\, e^{0.1495}$$

The linear heat demand is then computed as the ration between the linear heat demand density (LHD) and the route meter per supplied land of area (rm). Then we calculate the average pipe dimension (DN) using the following equation

*DN = 48.6 * ln (linear heat density [MWh/(rm.a)]) + 63*

Last, we calculate the network cost per linear meter (EUR/rm), as follows:

$C_{DH\text{-}Pipenetwork}$(DN) = (270 + 2.2*DN)

Following the method proposed the full potential scenario will require a total investment of EUR 1 560 billion, while in the case of high and medium density demand the investments in the network are of the order of EUR 128 billion and EUR 400 billion respectively. Figure 77 shows the unitary investment cost per unit of energy provided for different heat demand densities. As expected, the investments decreases with the increase of the heat demand density.

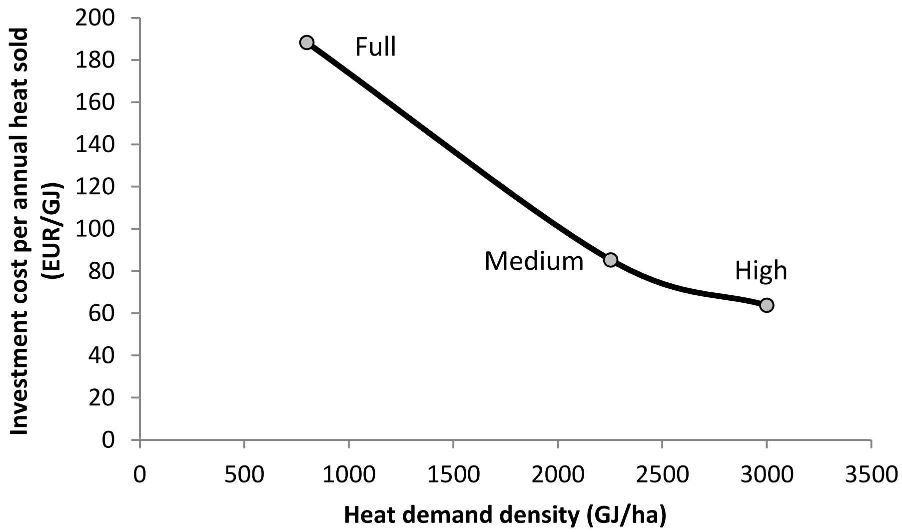

Figure 77. Investment costs related to the thermal network for different heat demand densities

5.2.2 Sensitivity analysis

— The role of thermal storage

In the previous section we presented results for four major scenarios for the two years under consideration that include thermal storage in combination with cogeneration and district heating. However, to better understand the role of thermal storage and its benefits it is worthwhile to compare the results between scenarios that consider both availability and non-availability of thermal storage. When doing so, we observe how the availability of thermal storage results in larger shares of heat supplied from centralised CHP plants. Thus, for the full potential scenario, the amount of heat provided from CHP increases by 4% while the production of electricity rises by 2%. This larger utilisation increases the higher overall systems efficiency by 1%.

If the utilisation of heat is restricted to those geographical areas with a certain level of heat demand density, in which the deployment of thermal networks is feasible, the effect of thermal storage on the overall system efficiency is reduced. This is noted due to the fact that CHP plants can operate at lower ranges, due to lower heat demands and thus adjusting both heat and power production to the demand at all times. Hence, for the high density scenarios, the presence of thermal storage only increases the production of heat from CHP by 0.2%. Electricity production decreases by 3% giving way to a larger contribution from renewable generation and therefore less curtailed renewable generation.

Regarding the impact of thermal storage in the amount of curtailed energy from renewables, it results in a reduction of the amount of curtailed energy. For the 2016 full potential CHP scenario the presence of thermal storage reduces curtailment by 3%. In 2050, thermal storage enables even a larger reduction of 8% due to a higher share of renewable power capacity (26% in 2016 and 56% by 2050 of the total power capacity). Therefore, thermal storage enables the potential utilisation of centralised combined heat and power in combination with district heating without compromising the penetration of renewable energies.

— Implications on the different levels of available heat demand

The availability of suitable heat sinks that could absorb heat from thermal networks determines the operation of the CHP plants. In the scenarios explored in this study, we have defined three level of demand that could be potentially supplied based on the heat demand density levels. Results show that the lower the heat needs per surface, the less contribution from CHP both in terms of heat and power production.

— Flexibility analysis

Energy storage enables additional flexibility options to maximise the use of renewable energy resources. According to the definition proposed, three alternatives serve as flexible options for the power system, namely: storage, interconnections (outflows) and curtailment.

In this regard, despite the efficiency and economic benefits presented, the effects of introducing combined generation to the power system are sometimes adverse. The option of delivering centralised heat at higher efficiencies and lower costs reduces the flexibility of the power system and may hinder the integration of renewable energy.

Figure 78 presents the comparison of different scenarios based on the aggregate load duration curve for the three strategies mentioned. We observe how, for the scenarios with available heat and power capacity, the three components increase due to the high operation of CHP plants and available renewable sources.

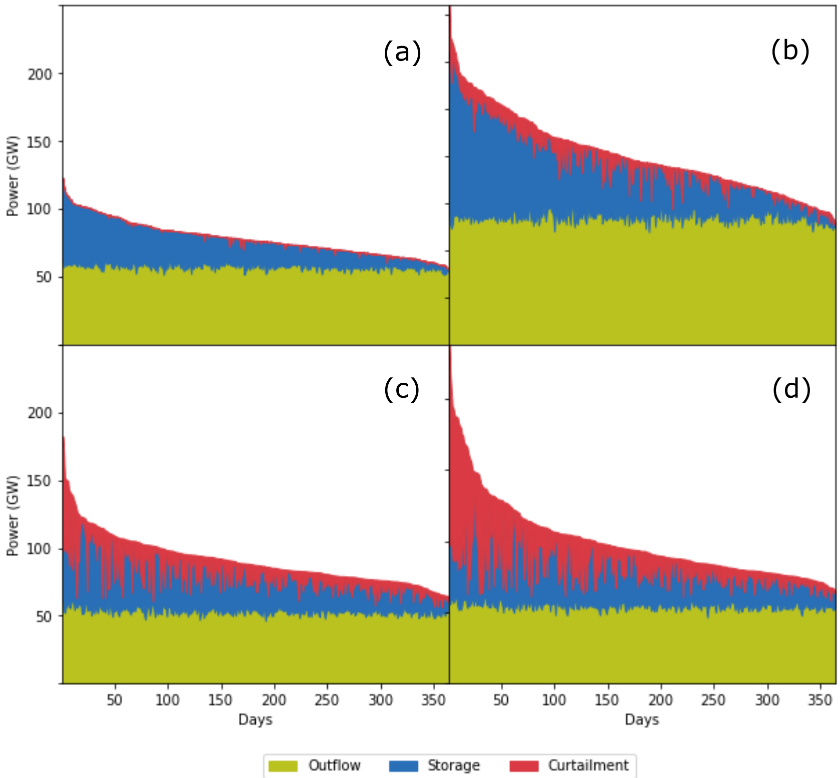

Figure 78. Flexibility options for different scenarios: (a) Base case 2016, (b) full CHP potential + thermal storage for 2016, (c) Base case 2050 and (d) full CHP potential + thermal storage for 2050.

6 Conclusions

The heating sector focusing on the built environment was thoroughly analysed describing its detailed energy break down, and related costs, emissions and efficiencies.

Power sector is getting decarbonised as the fossil fuel intensity of the EU electricity generation has fallen from 1.27 $kWh_{fossil}/kWh_{electric}$ in 2000 to 1.06 $kWh_{fossil}/kWh_{electric}$ in 2016. This makes decarbonisation from electric driven heating more attractive. In 2015 electric heating and cooling services in buildings added up to 366 TWh in the EU28, which make up 13.4% of the final electricity consumption. Under the baseline scenario electricity consumption is expected to increase a lot in all sectors by 2050, but the share of electric driven heating is expected to be only 6.8% of the total electricity demand, despite the fact that the total amount is rising as well.

By examining power and heat scenarios and their interactions in one study is necessary for a complete overview of the transition. In that context, two main energy transitions pathways of the heating sector were examined, namely electrification of heat and efficient heat and power production via cogeneration and district heating. The following conclusions were drawn:

— Electrification of heat

- Current heat electrification rates vary from 3% to 32%. Member States with an electrification rate below 5% are Denmark, Hungary, Lithuania and Romania. Member States with electrification rates above 20% are Finland Portugal and Sweden.
- If all current fossil-fuelled heat generation technologies were replaced by heat pumps overnight the combined emissions of the heat and power sector would be reduced by 16%. The exact percentage per Member State varies based on the current and projected composition of the power and heat sector. The biggest potential is found in FR with a 65% and the lowest potential in PL and EE with 4%. Without additional "clean" capacity additions the additional electricity demand for heating will be mainly generated by dispatchable sources which usually have higher emission rate than the average electricity generation mix. In a future decarbonized power system context the combined heat and power emissions would be reduced by 25% even without considering additional clean capacity.
- Based on the above scenario, heat pumps demand would be 26% of the total electricity demand adding 526 TWh to the final electricity consumption (2910 TWh). This demand would be unequally distributed between summer and winter season. The increase in the winter peak demand is expected to be 20% to 70% higher than today with an average of 41%. The biggest changes in absolute terms would be noticed in Germany (+108 GW), France (+26 GW) and Poland (+ 47GW).
- Firm power capacity of the current power system starts to become inadequate for electrification rates above 32% (replacing around 60% of fossil fuelled heat). Beyond that point, the role of flexibility measures will become more relevant. For the extreme future scenario, it would result into an average loss of load of around 2%, while some countries show lost load values of up to 7%.
- In this case, the energy not served can be reduced with a more flexible demand. By shifting just the 6% of the monthly peaks to off-peak time, the unserved energy is reduced by half.
- In the base scenario of the future power system scenario we observed a lot of curtailed renewable energy. In a fully electrified scenario, curtailed energy is reduced by 17% as electricity as this electricity is used to satisfy heating needs.

— Centralised cogeneration and District heating

- The current power plant fleet has the theoretical potential to satisfy 58% of the European space heating demand . The utilization of this CHP capacity results in a substantial cost reduction of the total energy system — 17% and 20% for the current and future scenarios respectively.
- If all current or future steam based power plants were operating into CHP mode together with district heating networks (including thermal storage), the overall efficiency of the energy system would increase significantly. In the current scenario, the efficiency raises from 63% to 76%, while in the future scenario (2050) it raises from 73% to 80%.
- The expected increase of the energy efficiency in the built environment will allow for a larger share of heat supplied from centralised cogeneration. As a result, in the future scenario, the share of heat

that can be covered from CHP reaches 70%. In other words, the ratio of the heating demand in the built environment to the available CHP capacity decreases over time.

- If the thermal power plants are operating in cogeneration mode, there is a notable increase in curtailment of renewable energy. It is estimated that this will fall in the range of 1 – 9% for the current scenario and 6 – 10% for the future one. Enhancing the interconnections or storage capacity could alleviate this effect.

6.1 Further work

Based on the methods and results presented in this report, further technical and policy recommendations can be provided by considering the following elements:

— Include optimal capacity expansion for a feasible heat electrification scenario

— Explore the real potential of centralised cogeneration and district heating of the remaining thermal power plant fleet, including a geo spatial analysis

— Quantify the trade-off between the two pathways trying to define the optimal pathway to decarbonise heating.

— Expand analysis to industrial sector

— Probe into more detailed climate effects and weather patterns

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List of abbreviations and definitions

CAES	Compressed air energy storage
CDD	Cooling degree days
COP	Coefficient of performance
DHW	Domestic hot water
EED	Energy efficiency directive
EPBD	Energy performance of buildings directive
HP	Heat pumps
IT	Information technology
HDD	Heating degree days
VRE	Variable renewable energy sources
PEF	Primary energy factor
ST	Thermal storage
PHS	Pumped hydro storage
NaS	Natrium Sulphur (Sodium Sulphur) electricity storage
GHG	Greenhouse gas
EC	European Commission
FEC	Final energy consumption

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Annexes

Annex 1. Literature review on heat decarbonisation

Head decarbonisation has gained interest lately. We looked in SCOPUS database for trends on the phrase "heat" AND "decarbonisation" existing in the title, abstract or keywords. The thematic area was limited to "Energy". 295 sources were identified. The following figures show their distribution.

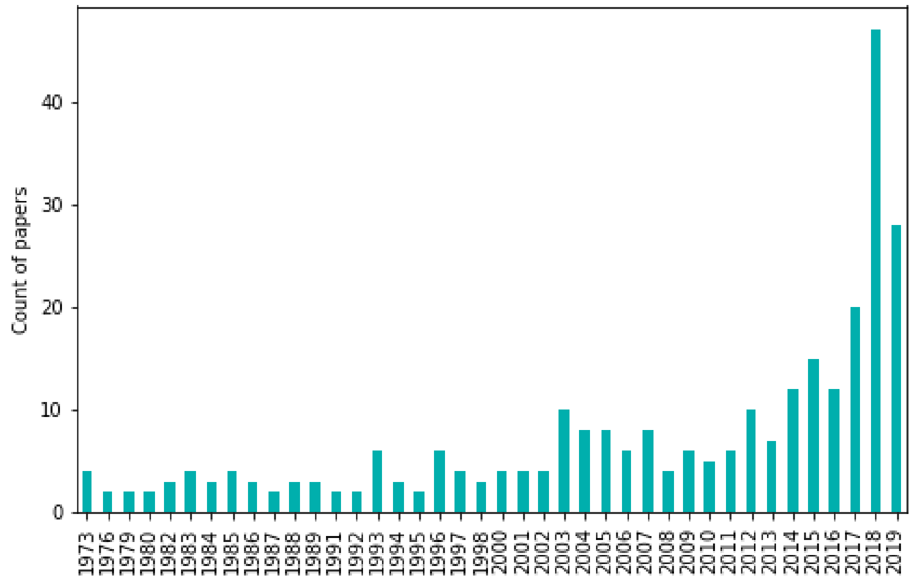


Figure 79. Number of sources mentioning "heat decarbonisation" per year (till April 2019)

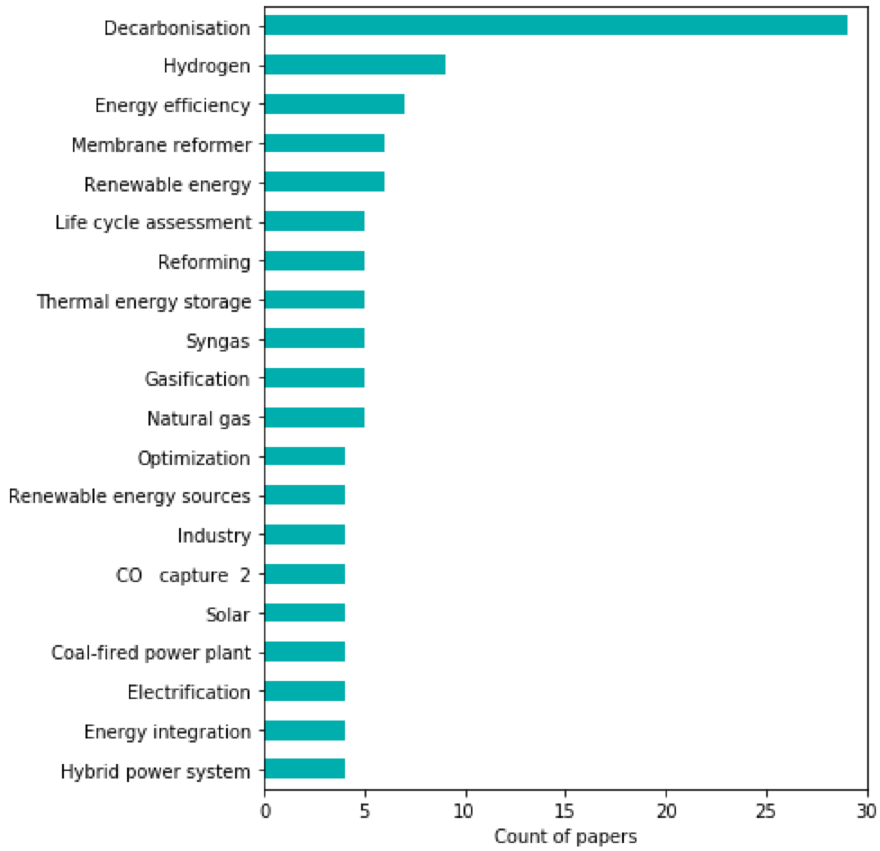


Figure 80. Number of keywords of examined papers (20 most common keywords plotted)

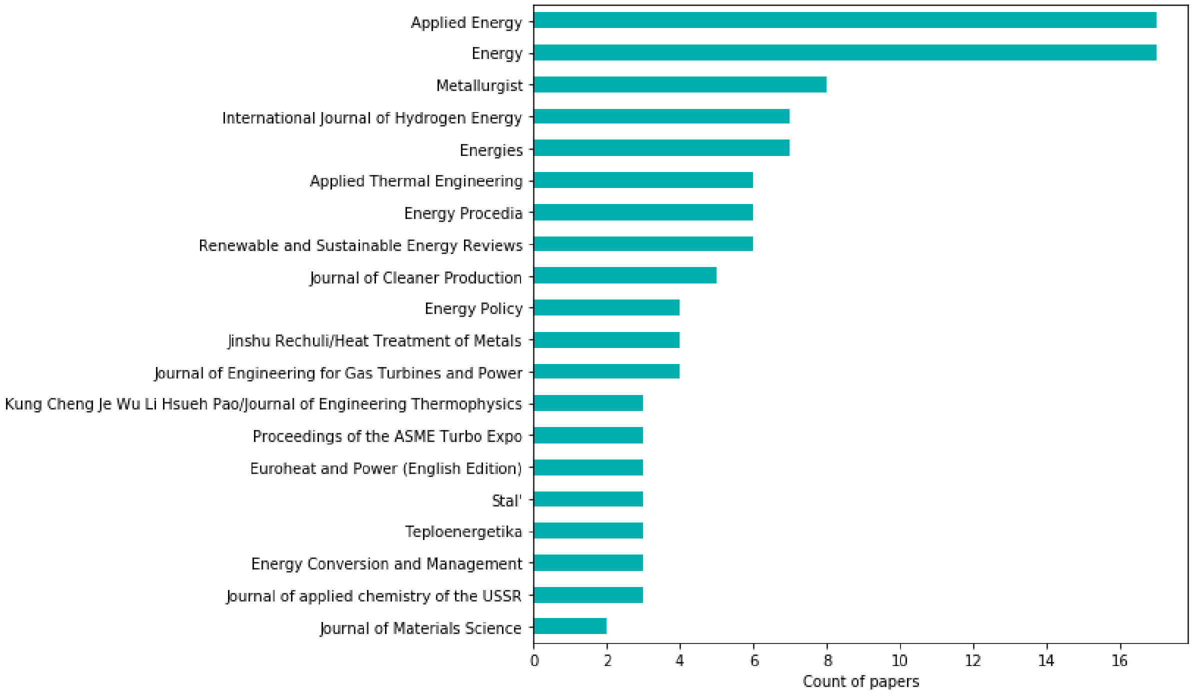


Figure 81. Number of papers per journal

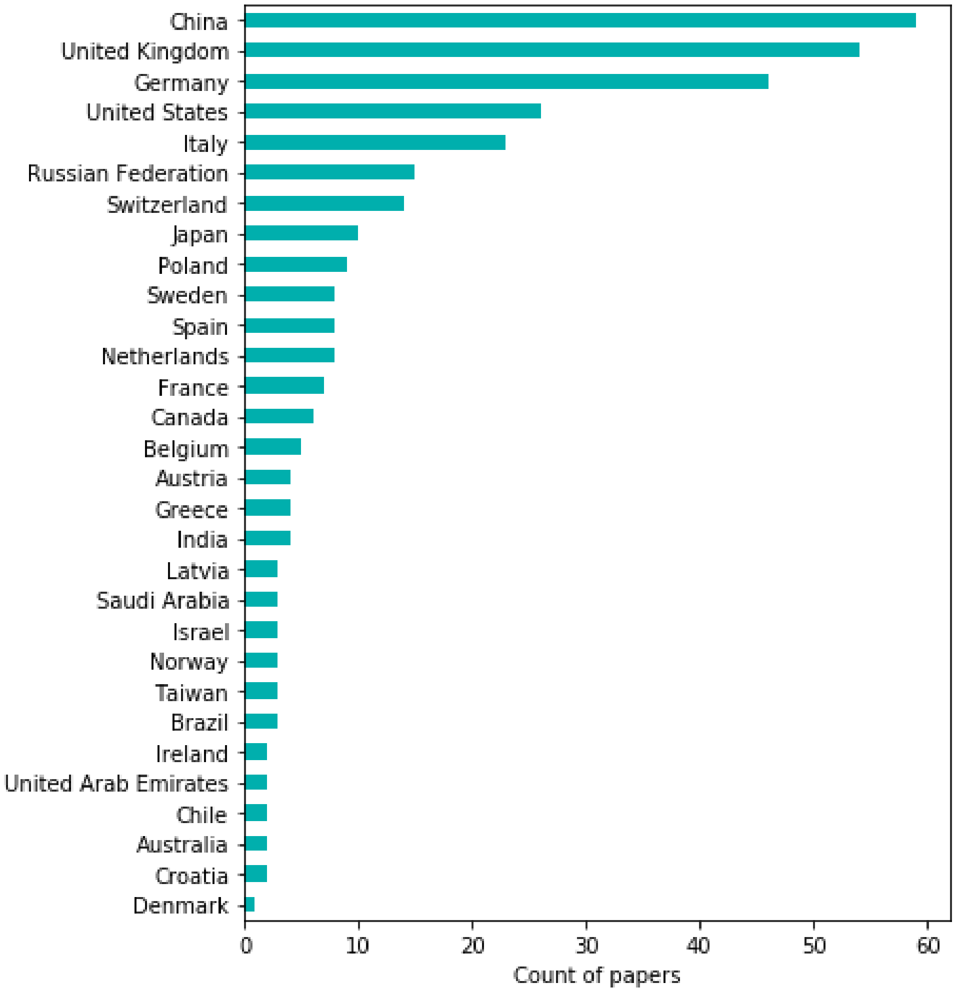
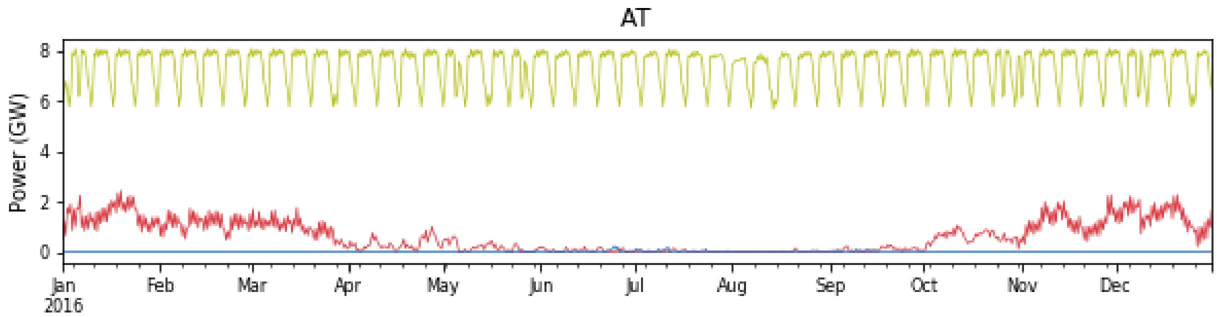


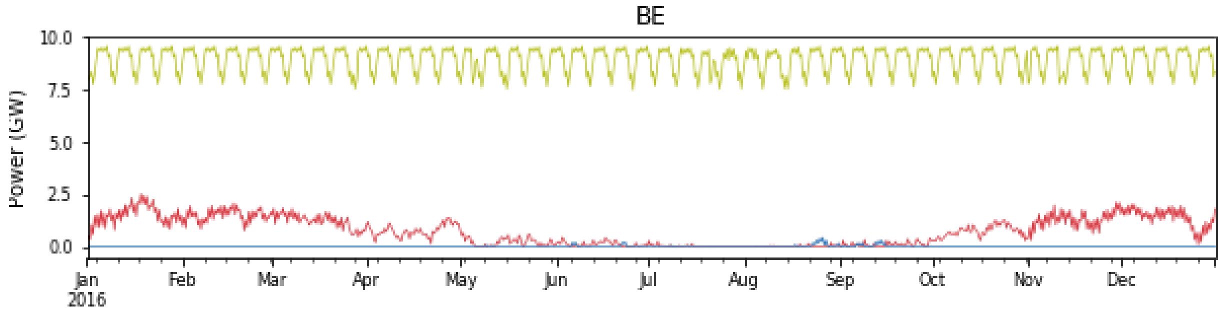
Figure 82. Number of papers per country (based on affiliation

Annex 2. Electricity decomposition plots of electricity load

Table 9. Hinge points and relevant spearman factors for heating and cooling

	Heat Hinge point (°C)	Spearman Factor	Cooling Hinge point (°C)	Spearman Factor
AT	21.1	0.529	17.84	0.15
BE	23.0	0.580	26.98	0.23
BG	19.0	0.735	27.30	0.59
CH	16.9	0.647	20.52	0.19
CY	19.2	0.494	20.46	0.86
CZ	22.4	0.681		
DE	23.3	0.444		
DK	23.7	0.483		
EE	24.0	0.759	23.00	0.28
EL	20.0	0.686	18.79	0.79
ES	20.6	0.378	19.09	0.70
FI	17.1	0.906		
FR	21.0	0.831	23.22	0.17
HR	19.3	0.604	15.86	0.62
HU	22.7	0.499	20.68	0.76
IE	17.3	0.357		
IS	20.1	0.731		
IT	19.6	0.212	20.69	0.57
LT	21.6	0.592	26.00	0.30
LU	14.5	0.334	24.65	0.32
LV	19.2	0.665	27.53	0.56
NL	23.3	0.412	27.00	0.48
NO	22.5	0.938		
PL	21.7	0.526	17.95	0.29
PT	20.5	0.160	19.36	0.48
RO	21.7	0.664	17.69	0.59
RS	24.0	0.835	26.10	0.50
SE	16.4	0.893		
SI	22.1	0.535	20.80	0.23
SK	24.0	0.627	21.08	0.31


AT
Power (GW)
0
2
4
6
8
Jan
2016
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


BE
Power (GW)
0.0
2.5
5.0
7.5
10.0
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2016
Feb
Mar
Apr
May
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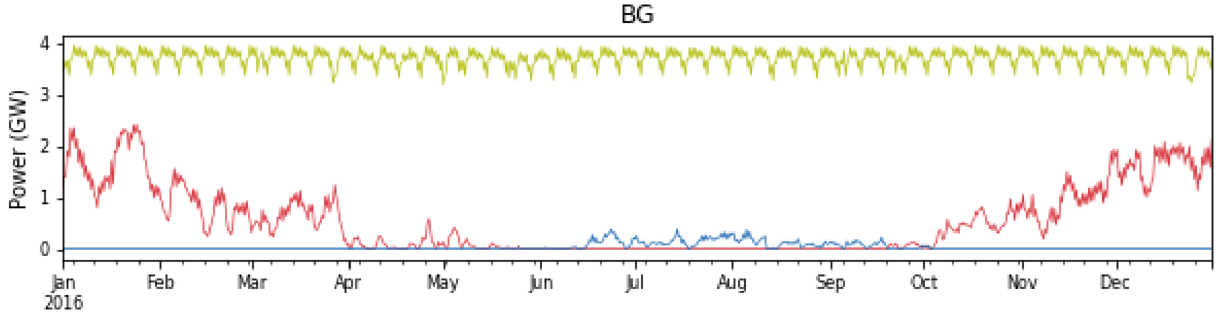
Jul
Aug
Sep
Oct
Nov
Dec


BG
Power (GW)
0
1
2
3
4
Jan
2016
Feb
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Apr
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Jul
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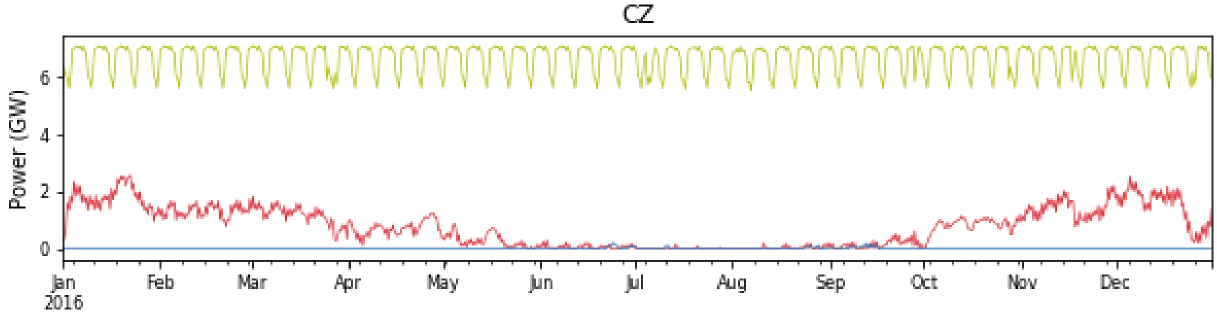
Sep
Oct
Nov
Dec


CZ
Power (GW)
0
2
4
6
Jan
2016
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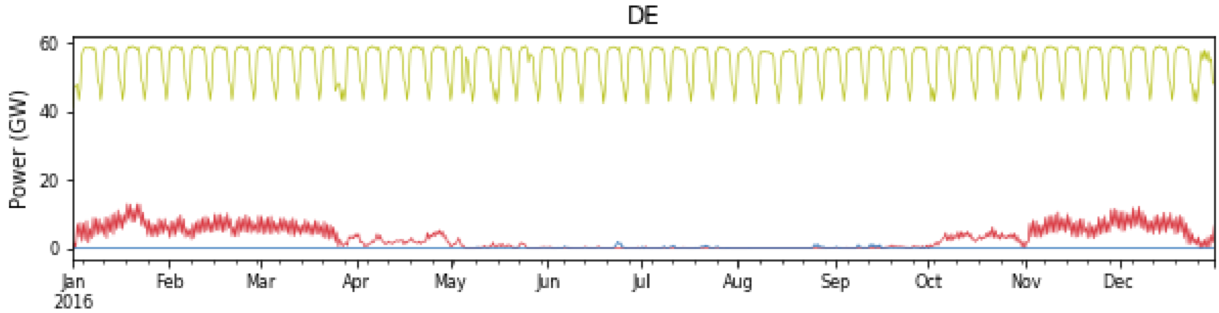
Sep
Oct
Nov
Dec


DE
Power (GW)
0
20
40
60
Jan
2016
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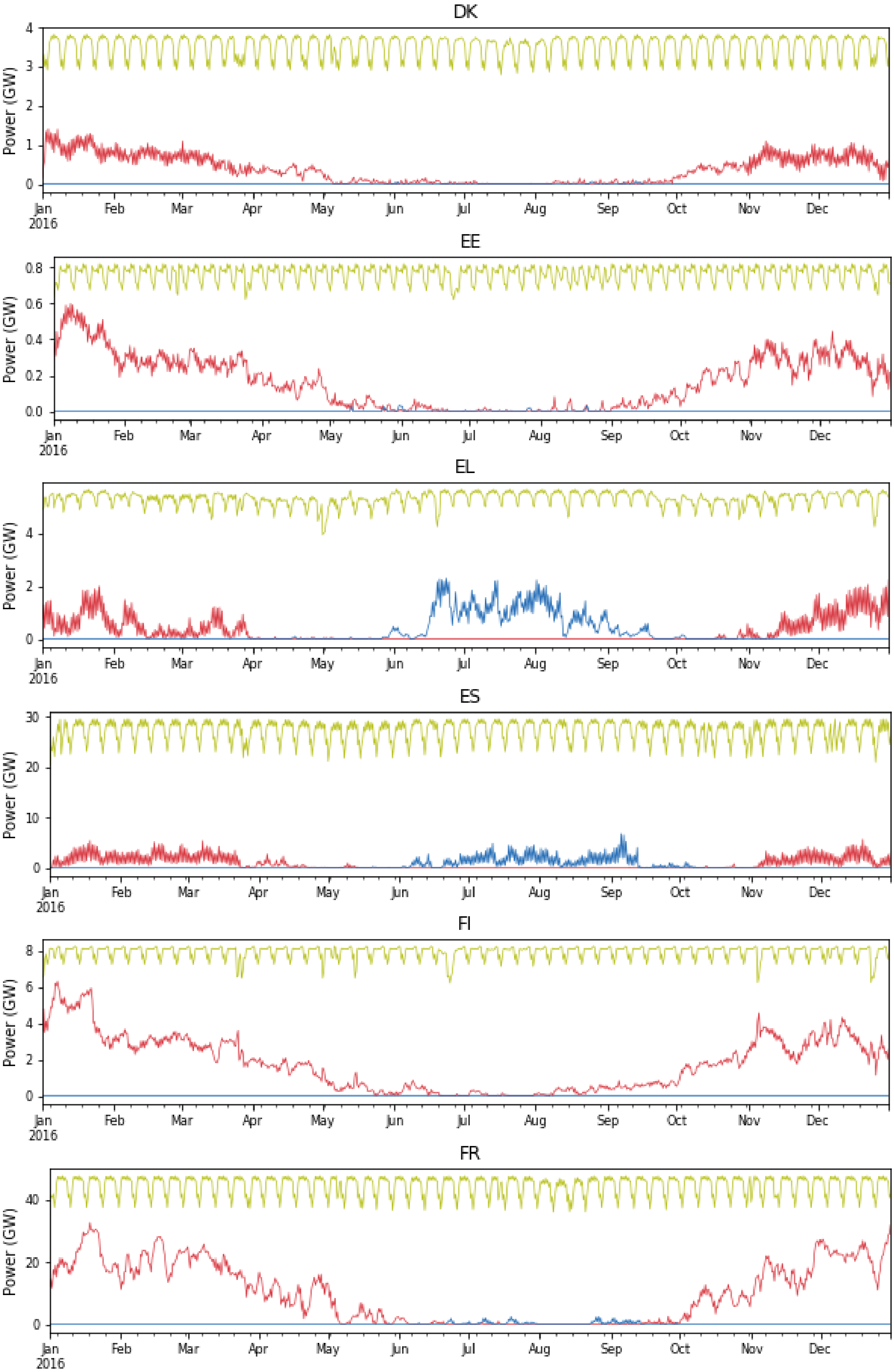
Sep
Oct
Nov
Dec


DK
EE
EL
ES
FI
FR
Power (GW)
Jan
2016
Feb
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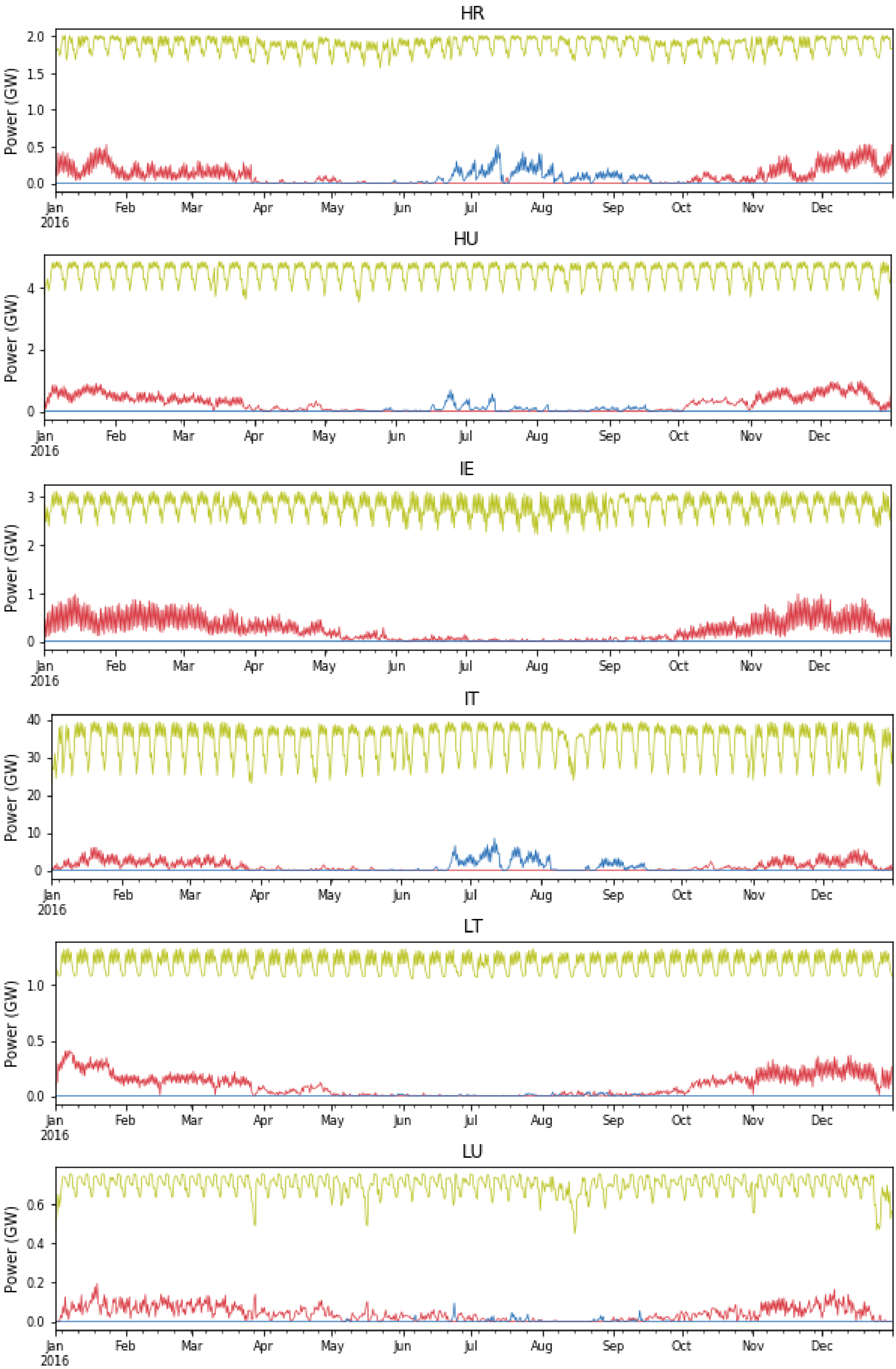
Oct
Nov
Dec


HR
HU
IE
IT
LT
LU
Power (GW)
Jan 2016
Feb
Mar
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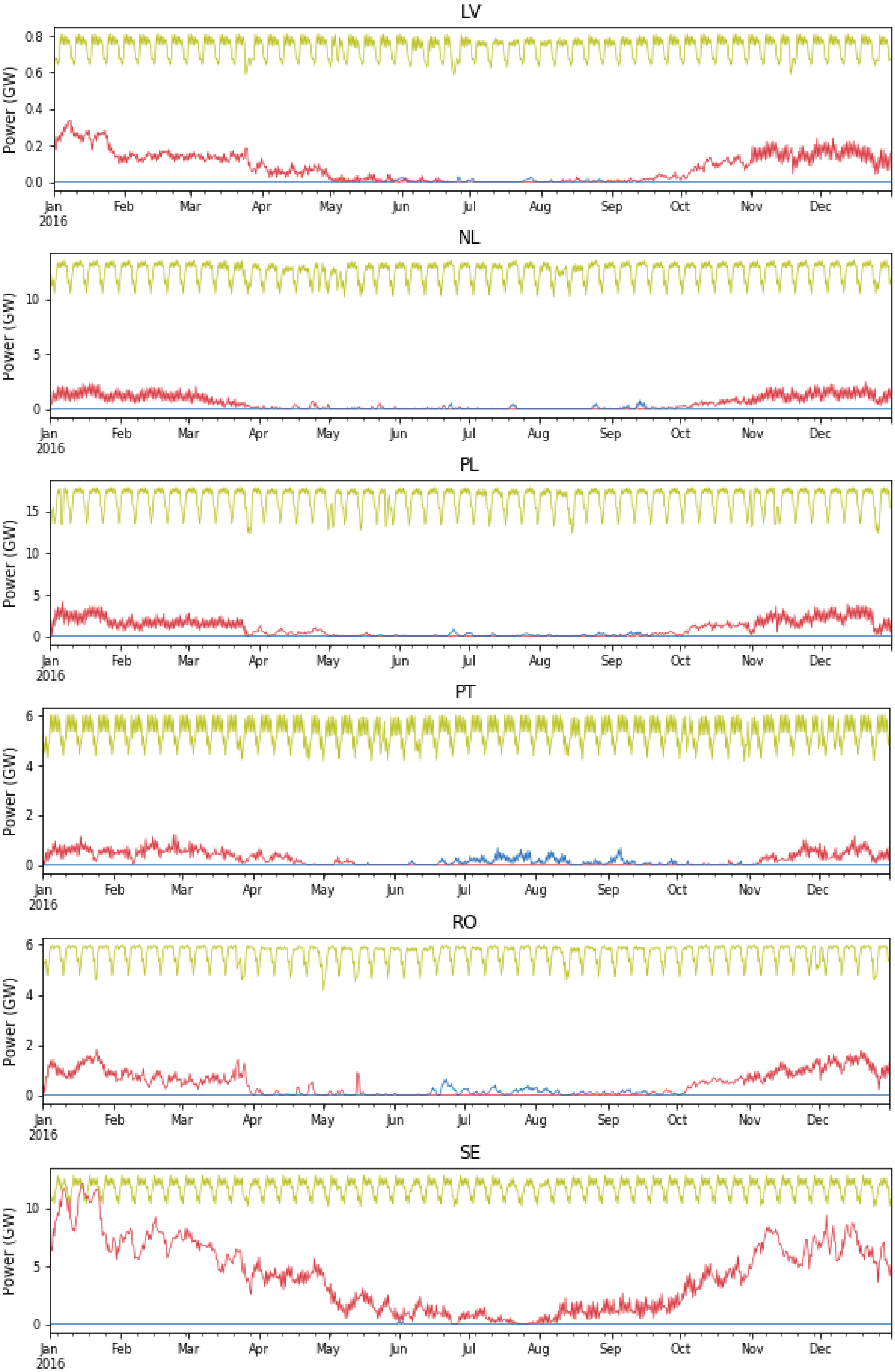
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


LV
NL
PL
PT
RO
SE
Power (GW)
Jan
2016
Feb
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Oct
Nov
Dec

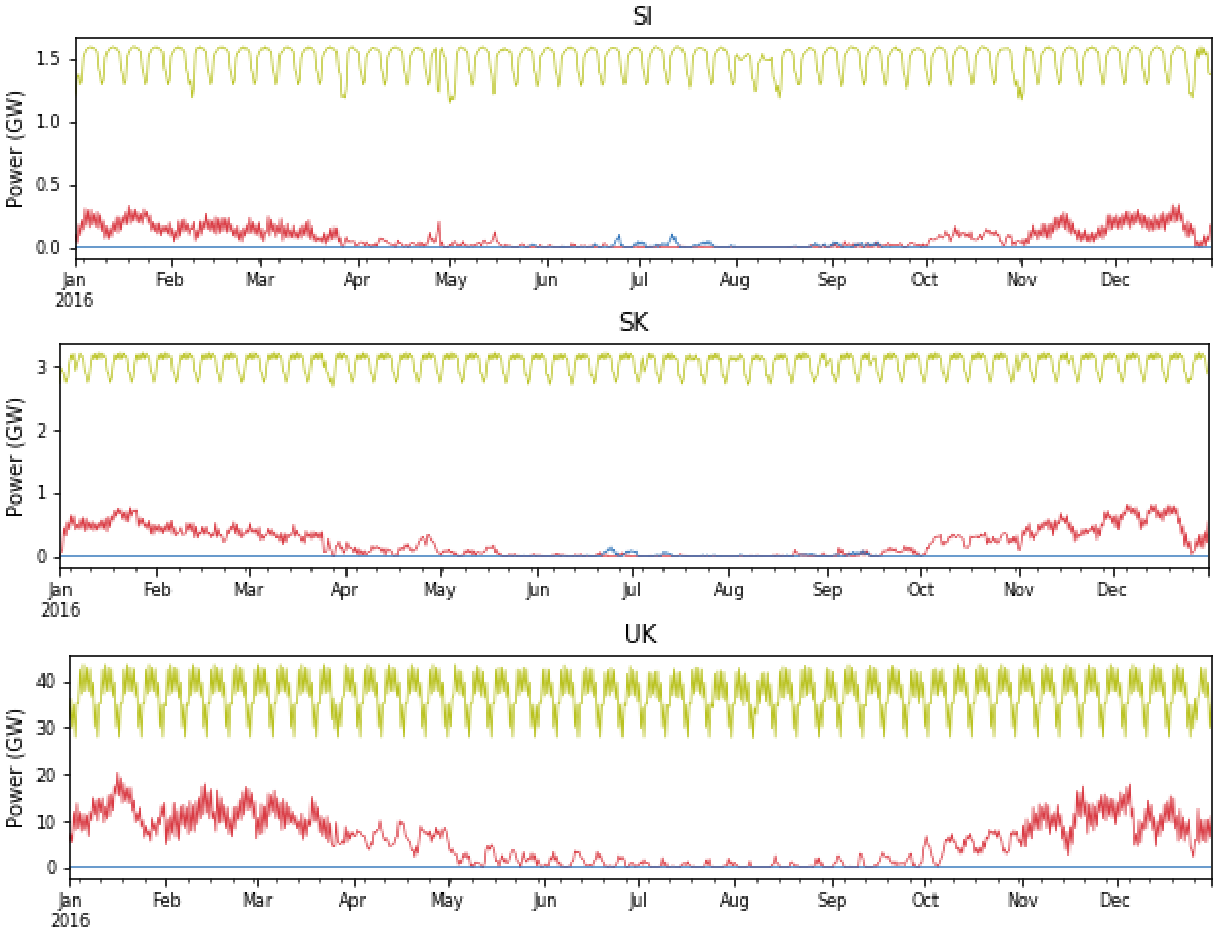


Figure 83. Decomposition of Power demand for heating (red) cooling (blue) and other purposes (green)

Annex 3. Variable renewable energy generation in Europe

Figure 84 shows the historical power output time series pattern of variable renewable generation, including hydro run-off river, solar, wind (onshore, offshore). The intermittent nature of them is observed, while their periodicity differs among countries as it depends heavily on the technology mix.

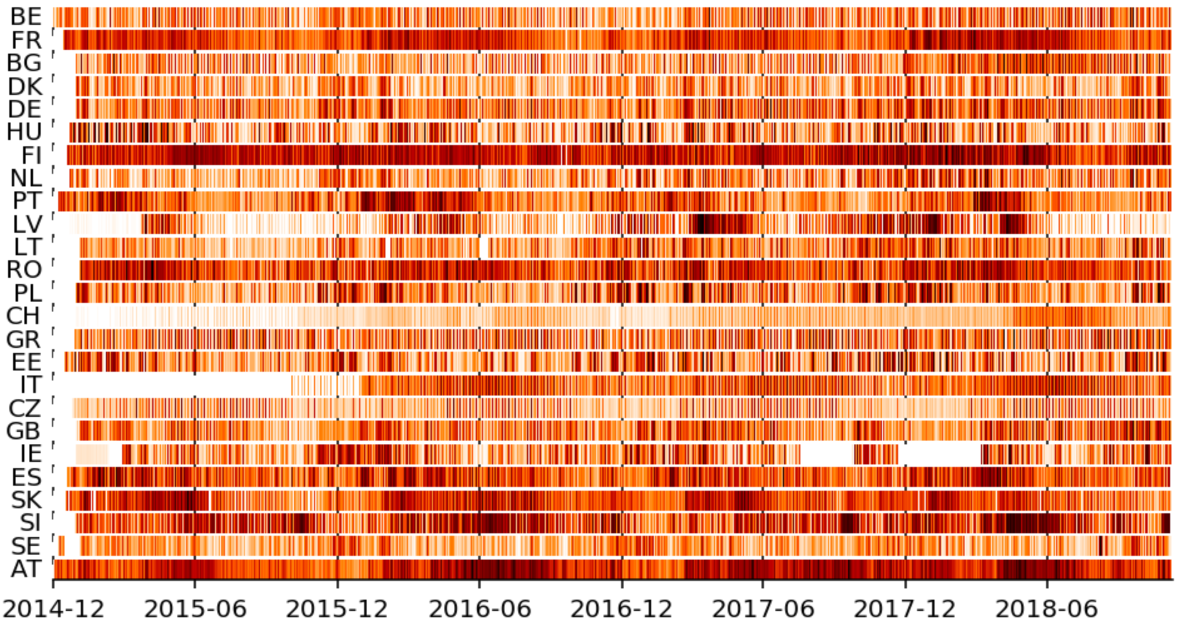


Figure 84. Variable renewable generation across EU. Data source: (ENTSOE 2018). The intensity of the colour corresponds to power generation from variable energy sources (the darker the colour the more energy is generated)

The correlation among these time series is also of great importance. A negative correlation is desired because when there is no generation in one place this could be offset with a different generation in another place. On the other hand, a positive correlation is not desirable. This is similar to portfolio risk management where when one asset falls ideally the other should rise.

Figure 84 indicates a lack of negative spatial correlation of variable generation due to the nature of weather phenomena, i.e. when there is not enough wind and sun in one country it is not certain that there will be wind and sun in most other countries. This shows the systemic risk on a system depending entirely on variable renewable generation. From a risk management point of view a negative correlation coefficient can help in the diversification of the generation mix which will reduce volatility in a generation portfolio.

The amount of wind energy entering the European electricity transmission system is expected to increase in next decades. Indeed, Europe is on the path towards a deep transformation of its energy system, triggered in part by Directive 2009/28/EC (also known as the Renewable Energy Directive), in which wind energy will play an important role.

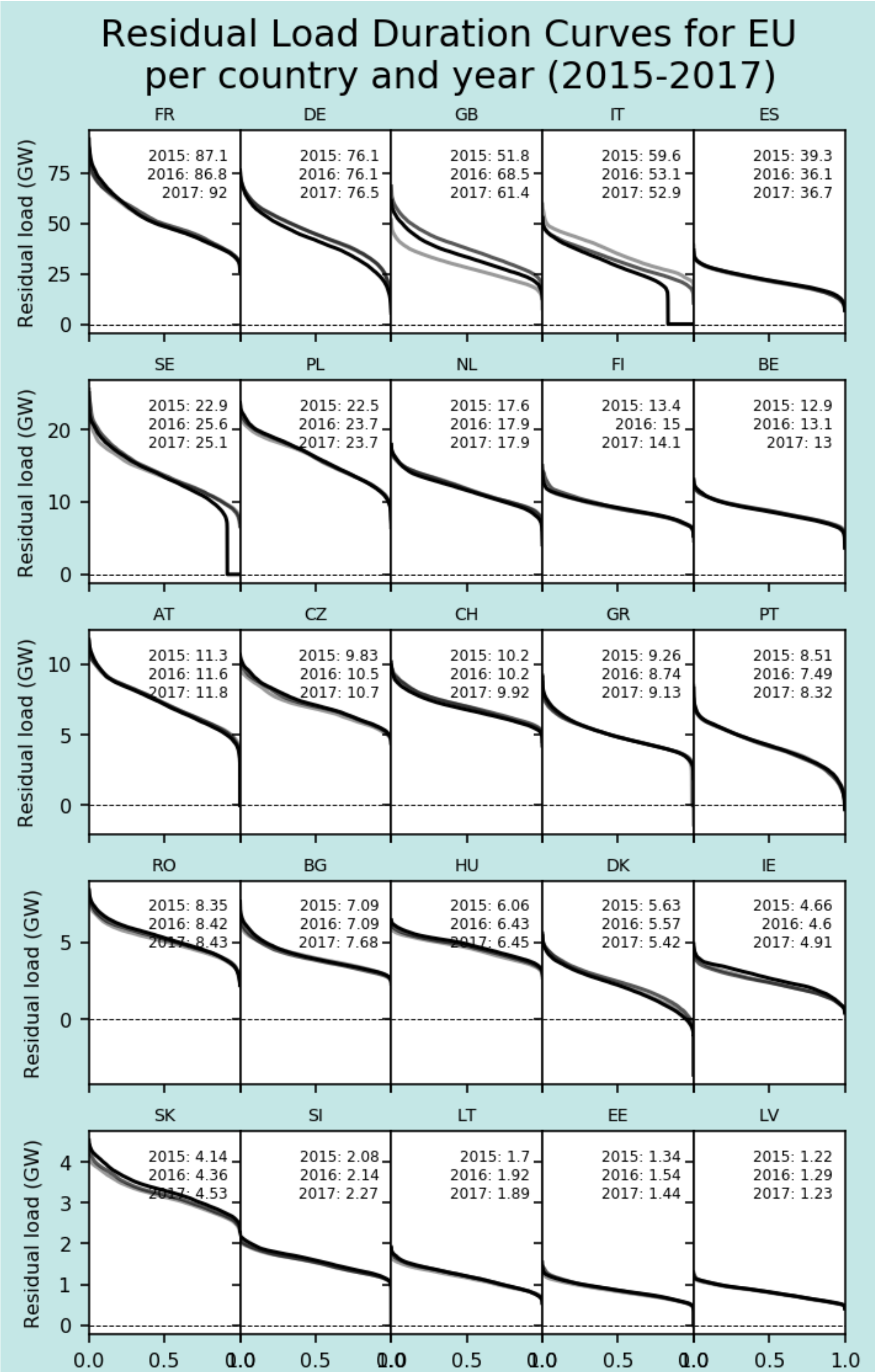


Figure 85. Load duration curve of Variable renewable generation across EU. Data source: (ENTSOE 2018). Countries are sorted and annotate by their peak residual load

Europe is large enough to be impacted by multiple weather systems at any one time and as a consequence, absolute values and time patterns of wind power generation are different in each European country because of these non-homogeneous meteorological conditions. A future pan-European power transmission grid aiming to dispatch electricity production throughout the continent will thus have to face the challenge of balancing in real time differently intermittent and strongly inhomogeneous resources.

In this study, based on the wind fields provided at daily resolution for the period 1961–2050 by 12 regional climate models involved in the ENSEMBLES climate modelling intercomparison project, we have evaluated absolute national and European wind power production and its expected changes following the evolution of climate in Europe. Moreover, we have suggested a methodology to investigate in a quantitative way the complementarity among wind power patterns in different countries. Results show that the evolution of climate in Europe as projected by the ENSEMBLES participants, is not expected to have major impact on absolute wind energy production. Furthermore, the complementarity of wind energy patterns in different countries can be exploited by better integration of trans-boundary power exchange in Europe. For this reason, results are also discussed in the light of the design and dimensioning of the European electricity transmission system, with a special emphasis on the cross-border interconnections issues.

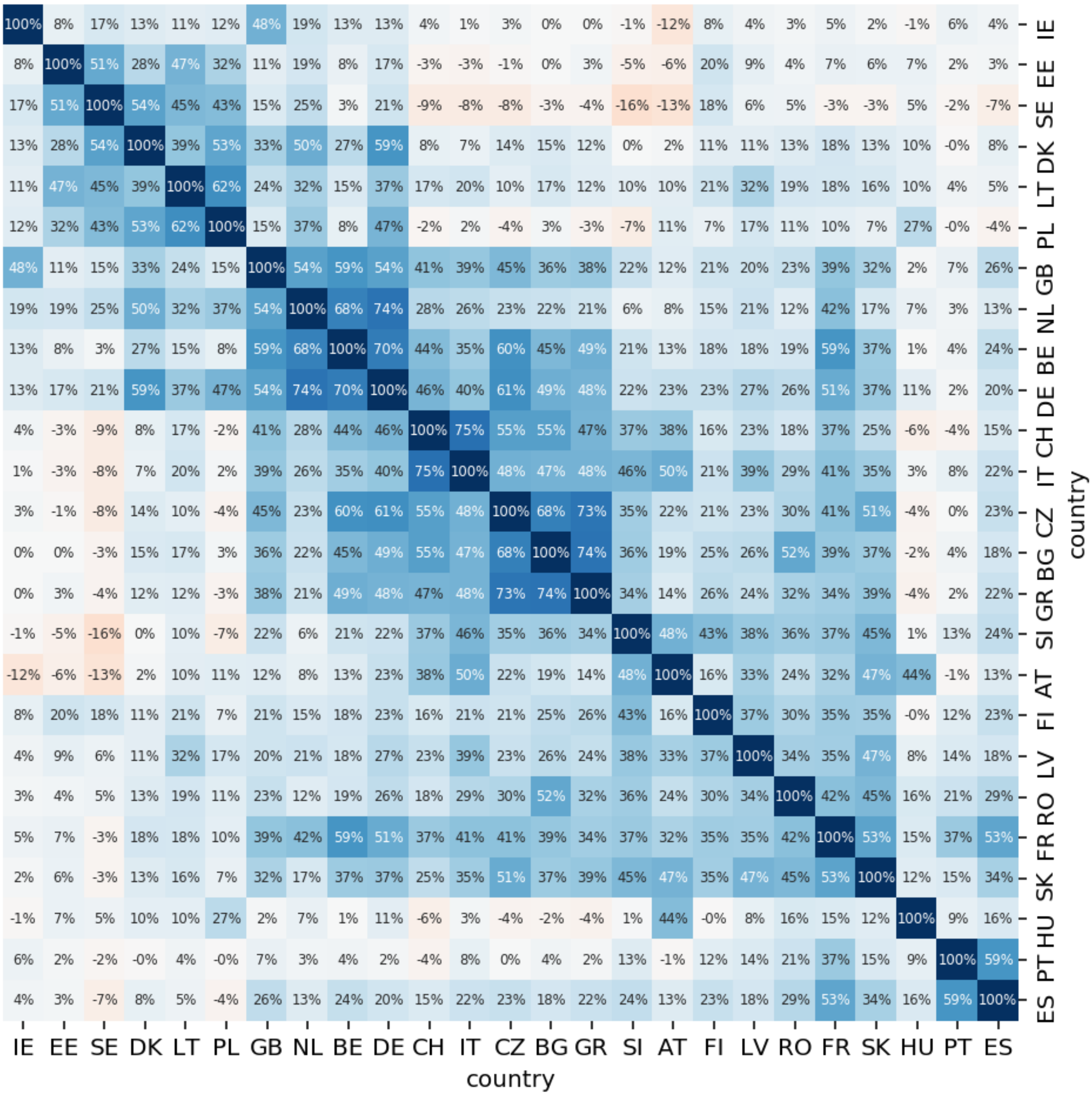


Figure 86. Correlation of variable renewable generation (countries are ordered and clustered based on their similarity).

With an increased renewable energy capacity this characteristic will become much more emphasised. The scenarios and concepts described in this report aim to alleviate that effect.

Annex 4. Comparison with heat demand data sources

In this section we present the comparison of the different data sources we have used to build the current and future heat demand for the building sector in Europe.

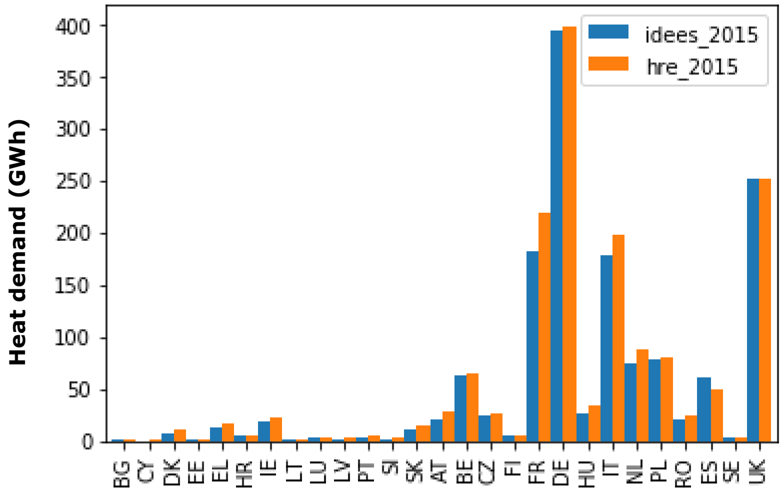


Figure 87. National heat demand comparison for different data sources: (Mantzos et al. 2017, Nijs et al. 2017)

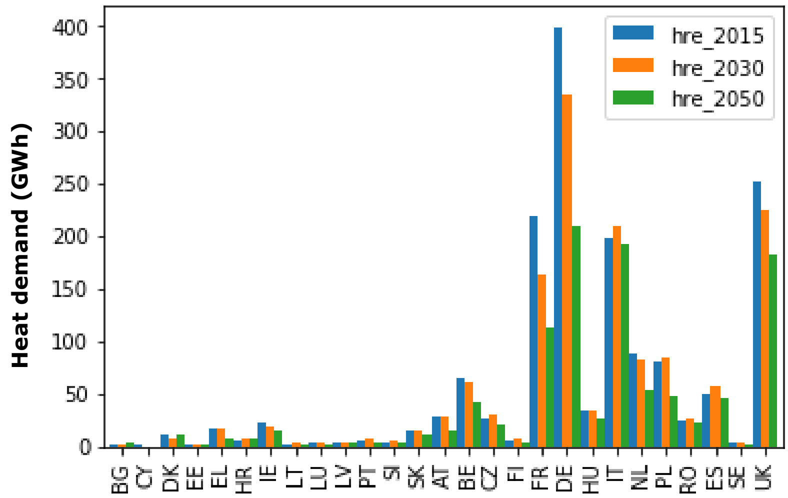
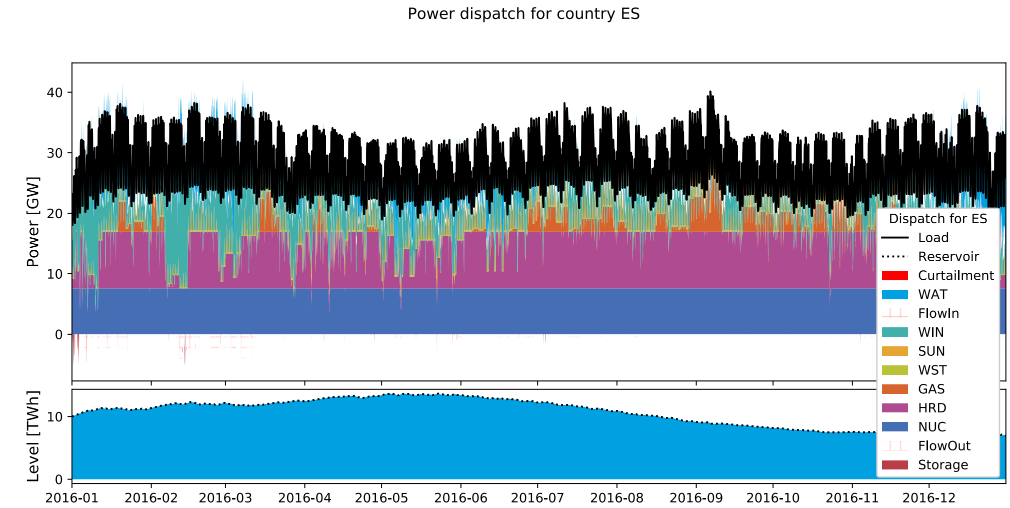
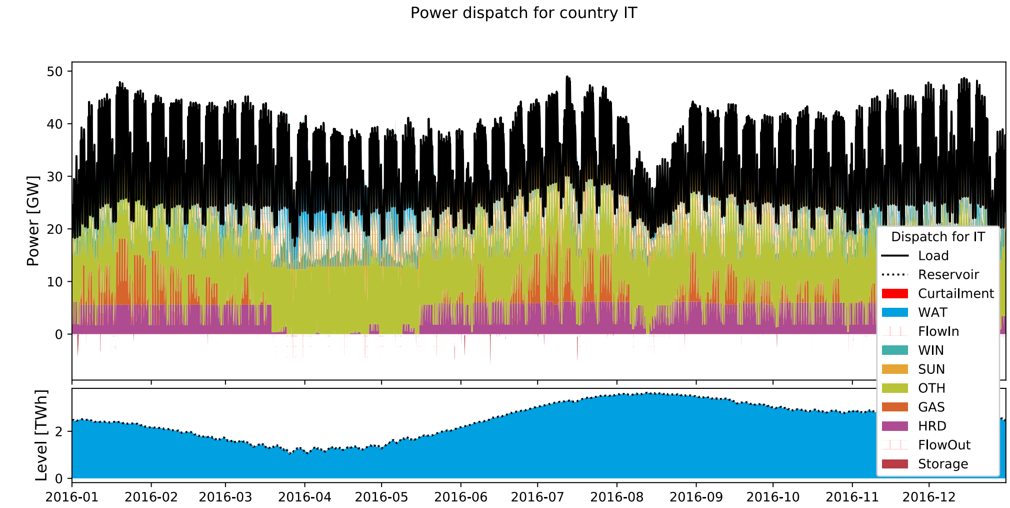


Figure 88. Present and future projections of national heat demand in Europe. Data source: (Nijs et al. 2017)

Annex 5. Example dispatch plots

Annex 5.1. Example dispatch plots for the base case for 3 countries





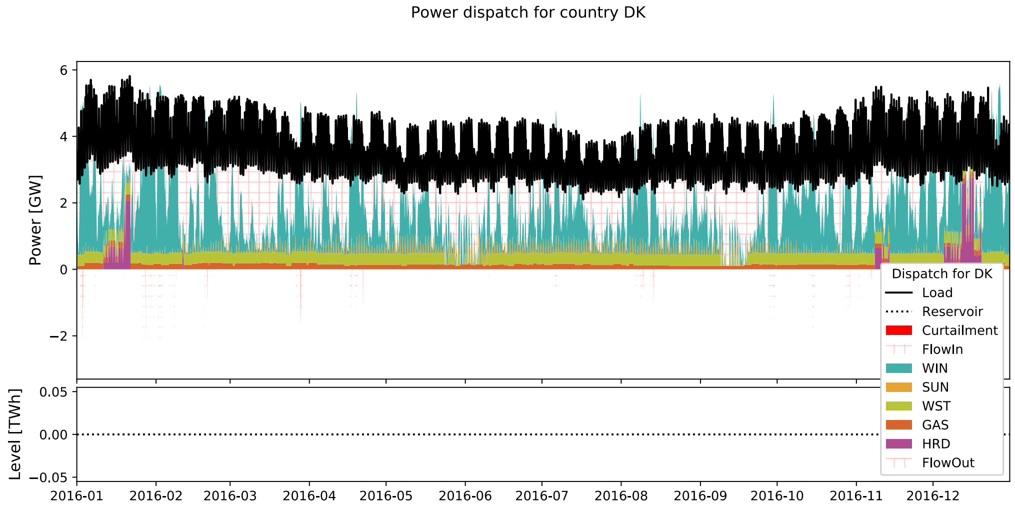


Figure 89. Example dispatch plots

Annex 5.2. Cogeneration and district heating scenarios

In this section, a set of detailed dispatch charts are presented to illustrate the effect of different features included in this set of scenarios. Figure 87 — 88 depict the dispatch for a week in winter for three 2016 scenarios: base case, full potential scenario without thermal storage and full potential scenario with thermal storage.

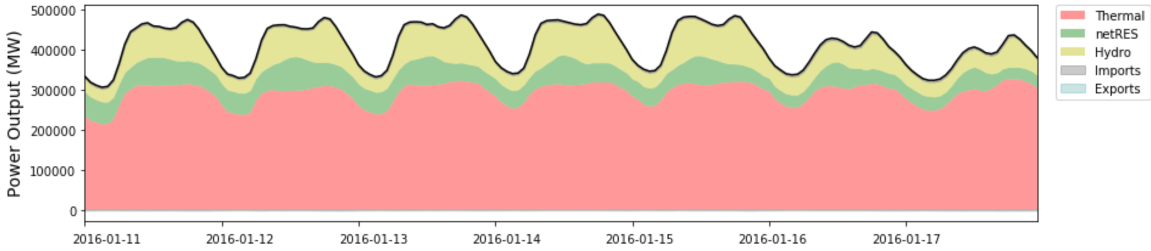


Figure 90. Power dispatch. Base case scenario 2016

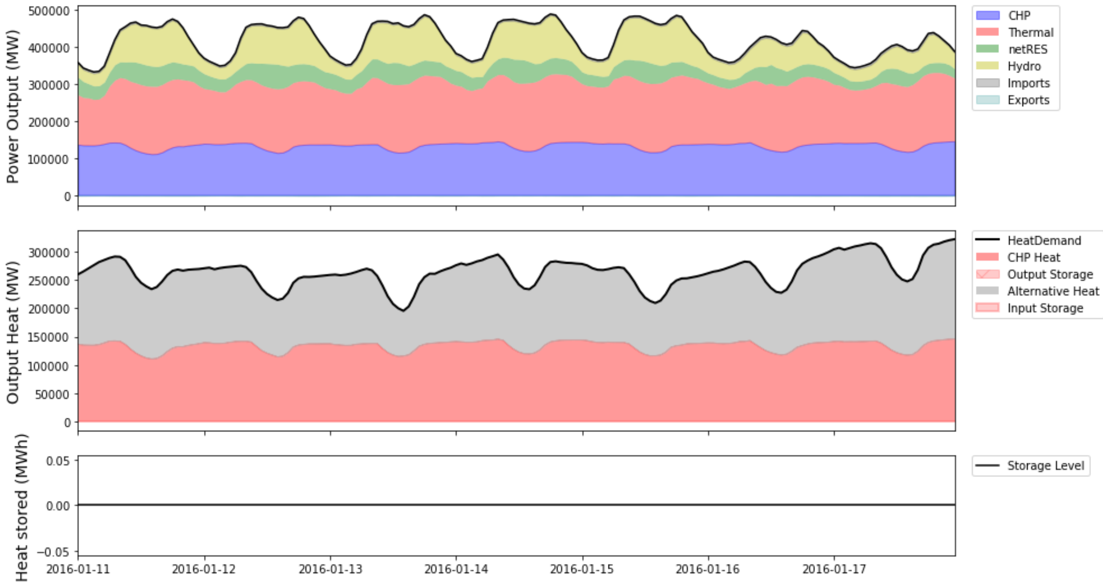


Figure 91. Heat and power dispatch. Full potential scenario with no thermal storage

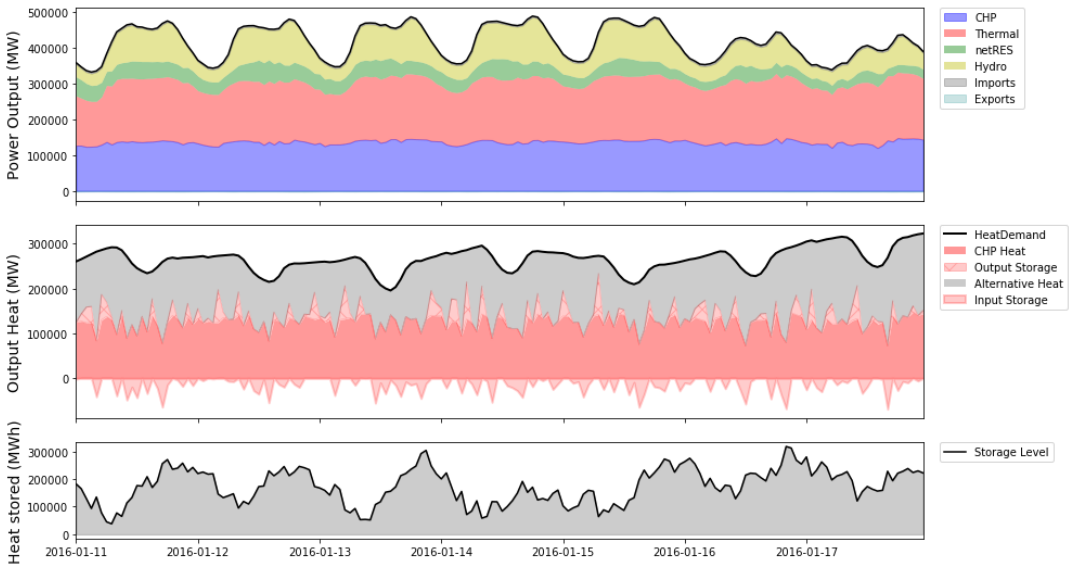


Figure 92. Heat and power. Full potential CHP and thermal storage scenario

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