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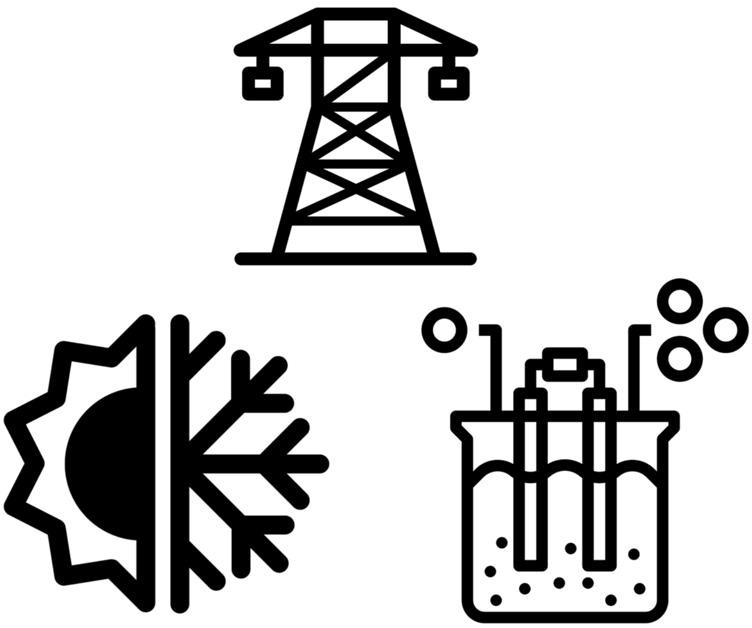
INTERNATIONAL ENERGY AGENCY
TECHNOLOGY COLLABORATION PROGRAMME ON
DISTRICT HEATING AND COOLING



IEA DHC ANNEX TS3: HYBRID ENERGY NETWORKS

APPENDIX G
NATIONAL SCALE ASSESSMENTS – DETAILLED SIMULATION RESULTS

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Citation:

Please refer to this report as:

Peter Sorknæs, Aalborg University: IEA DHC Annex TS3 Guidebook, Appendix G National Scale Assessments – detailed simulation results, 2022

CONTENT

1 INTRODUCTION

This Appendix is part of the IEA DHC Annex TS3 guidebook. The full guidebook is available at https://www.iea-dhc.org/the-research/annexes/2017-2021-annex-ts3

Author: Peter Sorknæs, Aalborg University,

This appendix is a supplement to Chapter 4 of the guidebook for IEA DHC Annex 3 on Hybrid Energy Systems. The method and scenarios are described in Chapter 4 of the guidebook, this appendix mainly present the results. For more on the scenarios see the main guidebook.

All technology costs have been updated using technology data from the Danish Energy Agency (Danish Energy Agency, n.d.) (accessed December 2020). To convert these numbers from Danish costs to Austrian costs, the method described by Guddat et al. (Max Gunnar Ansas Guddat et al., 2017) has been used. For costs associated with hydro power, geothermal electricity and industrial excess heat, the original Heat Roadmap Europe 4 costs (Paardekooper et al., 2018a) have been maintained. The costs used for Denmark are like those described in (Lund et al., 2021b), which is also based on the Danish Energy Agency (Danish Energy Agency, n.d.), though as the cost data in this source has been updated for DH fuel boilers, electric boilers, solar thermal, seasonal solar storage, and individual fuel boilers, these costs have been updated accordingly.

All the chosen scenarios have been developed in EnergyPLAN. The 2050 scenarios used for Denmark were originally created using v16 (Lund et al., 2021b). The models used for Austria were originally developed in v14.2 (Paardekooper et al., 2018b). Using different versions of EnergyPLAN would result in different outcomes, and therefore to make the results comparable, all scenarios presented are instead simulated in EnergyPLAN v16.

1.1 METHOD FOR LOW DISTRICT HEATING SCENARIOS

Austria

The HRE scenario is used as a base for making an Austrian low DH market share scenario for 2050, where the DH market share is decreased from 50% to 42% while maintaining the same total heat demand. Therefore, the heat demand supplied by individual heating solutions are increased by the reduced DH heat demand (excl. DH grid losses), keeping the same share of different individual heating solutions of the total individual heating demand. More specifically, the following changes were made to the HRE scenario to create a low DH market share 2050 scenario for Austria:

- Reduced the DH demand to deliver 42% of end-use consumption (down from approx. 50%), meaning a reduction from 25.03 to 21.43 TWh/year. The lower DH market share is equal to the Decarbonisation scenario for Austria from the Heat Roadmap Europe 4 study (Paardekooper et al., 2018b).

- Individual HP electricity demand increased from 25.5 to 29.1 TWh/year.
- Annual costs of DH grids reduced from 700 M EUR to 420 M EUR.
- DH fuel boiler capacity set to cover 120% of peak demand, reduced from 10.45 GW to 8.95 GW.
- The seasonal storage for solar DH and industrial excess heat is reduced from 73.71 to 63.11 GWh
- DH HP capacity reduced from 1,200 to 1,027 MW_e.
- Electric boiler capacity for DH production reduced from 1,200 to 1,027 MW_e.
- Industrial excess heat utilized for DH reduced from 2.48 to 2.13 TWh/year.
- Geothermal heat for DH reduced from 0.21 to 0.18 TWh/year.
- It is assumed that DH from waste incineration and excess heat from electrofuel production remains unchanged. As the production remains unchanged and provides baseload in the DH system, it is assumed that other baseload units should be reduced to not produce too high levels of non-usable heat in the low heat demand season. Therefore, first the geothermal heat capacity was reduced until the level of non-usable heat in percentage of the total DH demand was the same as with high DH demand. If more reductions were needed to reach this, then reductions were made to the solar thermal DH capacity. Based on this method, the DH geothermal heat capacity was reduced from 0.21 to 0 TWh/year, and thereby removed, and as this is not sufficient to reach the same level of non-usable heat, the solar thermal DH capacity was reduced from 0.74 to 0.2 TWh/year.

In case nothing else is indicated in the list above, each change is made based on the percentage reduction in yearly DH production

Denmark

The IDA2045 scenario has a DH market share of 66% of the total heating demand. IDA2045 is used as a base for making a Danish low DH market share scenario in 2050, where the DH market share is decreased to 50% while maintaining the same total heat demand, and therefore the heat demand supplied by individual heating solutions is increased by the reduced DH heat demand (excl. DH grid losses), keeping the same share of different individual heating solutions of the total individual heating demand. More specifically the following changes are made to the IDA2045 scenario to create the low DH market share 2050 scenario for Denmark:

- Reduced DH demand to deliver 50% of end-use consumption. 75% of these DH demand reductions are made in smaller DH areas (production decreased from 11.88 to 4.45 TWh/year) and 25% in larger DH areas (production decreased from 23.75 to 21.627 TWh/year).
- The demand moved from DH is instead supplied by individual HPs, and this demand has thereby been increased from 15.08 to 21.97 TWh/year. Individual Solar thermal supplementing individual HPs increased from 2.4 to 3.497 TWh/year.
- DH Fuel boiler capacity reduced from 4,644 to 1,863 MW for smaller DH areas and from 7,630.5 to 7,328 MW for larger DH areas to maintain these at 120% of peak DH demands.
- Solar thermal DH is reduced from 1.65 to 0.763 TWh/year in smaller DH areas and from 0.45 to 0.41 TWh/year in larger DH areas. Seasonal storage capacity is reduced from 10

to 4.63 GWh in smaller DH areas, and from 40 to 36.42 GWh in larger DH areas. This is based on a percentage reduction in yearly production.

- Electric-driven HP capacity is reduced from 700 to 324 MW in smaller DH areas, and from 1,600 to 1,457 MW in larger DH areas. This is based on a percentage reduction in yearly production.
- Electric boiler capacity is reduced from 500 to 232 MW in smaller DH areas, and from 1,000 to 910 MW in larger DH areas. This is based on a percentage reduction in yearly production.
- Industrial excess heat utilization is reduced from 2.15 to 0.995 TWh/year in smaller DH areas, and from 6.35 to 5.782 TWh/year in larger DH areas. This is based on a percentage reduction in yearly production.
- CHP capacity is reduced from 1,461 to 676 MW_e in smaller DH areas, and from 2,650 to 2,413 MW_e in larger DH areas, with condensing capacity of the CHP units in the larger DH areas reduced from 3,100 to 2,823 MW_e. This is based on a percentage reduction in yearly production.
- Waste incineration remains unchanged as waste incineration is not due to DH demands. As waste incineration remains unchanged and is only present as a baseload unit, the geothermal capacities in smaller DH areas and larger DH areas are reduced until the DH excess heat production is the same as with high DH demand in percentage of the total DH demand. This results in a reduction of geothermal production from 2.1 to 1.26 TWh/year in smaller DH areas and in larger DH areas from 5.44 to 3.28 TWh/year.
- The increased electricity demand for HPs for individual heating and the decreased CHP capacity increases the need for power plant capacity, which is increased from 1,700 to 2,900 MW_e. The technology used is simple cycle gas turbines.

As with the IDA2045 high DH scenario, the yearly CEEP and gas balance has been maintained. To ensure this the P2G production from CO_2 methanation has been increased by 12.35 TWh/year. The maximum capacity of P2G is changed to 1,086 tons CO_2/hour to accommodate the increased gas production. The additional demand for electrolytic H_2 means that the electrolysis capacity is increased to 8,288 MW and the H_2 storage is increased to 553 GWh. The extra electricity demand means that the PV is increased to 11,985 MW and offshore wind power is increased to 16,868 MW.

DIRECT ELECTRIFICATION OF DISTRICT HEATING

In this section the results of changing the DH electric boiler capacity and DH HP capacity in the scenarios are shown and discussed.

VARYING LEVELS OF ELECTRIC BOILER CAPACITY IN DISTRICT HEATING

In this section the electric boiler capacity that is connected to DH is changed from 0% to 200% of the initial installed capacity in the future high DH scenario for each country, and the DH HP capacity is kept unchanged. For Austria this means that 100% correspond to 1.2 GW electric boiler capacity, and for Denmark 100% correspond to 1.5 GW electric boiler capacity.

Figure 1 shows the change in the marginal variable RES production needed to maintain same CEEP value as described in Chapter 4 of the guidebook at different electric boiler capacities installed in the scenarios. The change in marginal variable RES production is relative to the production in the original scenario.

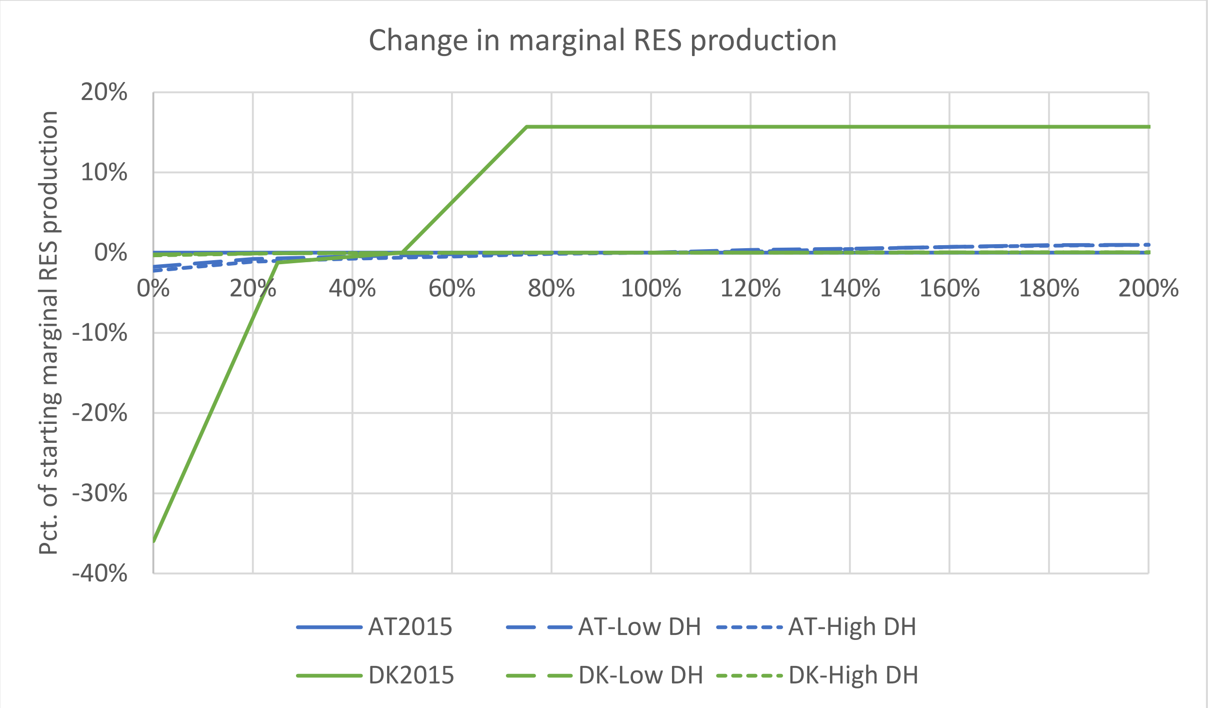

Figure 1: The change in marginal RES production for each of the different scenarios. For AT the marginal RES production is PV and for DK it is offshore wind power. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW electric boiler capacity, and for DK scenarios 100% correspond to 1.5 GW electric boiler capacity.

As shown in Figure 1, more electric boiler capacity allows for more marginal variable RES capacity in all scenarios, except for the AT2015 scenario, as in this scenario other technologies are included that allow for the full integration of the installed the variable RES, meaning that the CEEP value is zero. The future high DH scenarios allow for more potential integration than their low DH market share counterparts. The change in DH electric boiler capacity especially affect the relative capacity in DK2015, as few other flexibility options exist in this scenario, removing or reducing the existing capacity reduces the relative capacity of offshore wind power, where the current installed electric boiler capacity being around the 50% mark. It is important to note that the offshore wind power production is lower in the 2015 scenario than in the 2050 scenarios. More electric boiler capacity allows for further integration of offshore wind power, but only up to a certain capacity, which is due to the heat production from electric boilers evens out, as can be seen in Figure 2. Figure 2 shows the heat production of electric boilers and HPs, at different levels of electric boiler capacity, relative to the original high DH scenario of the country.

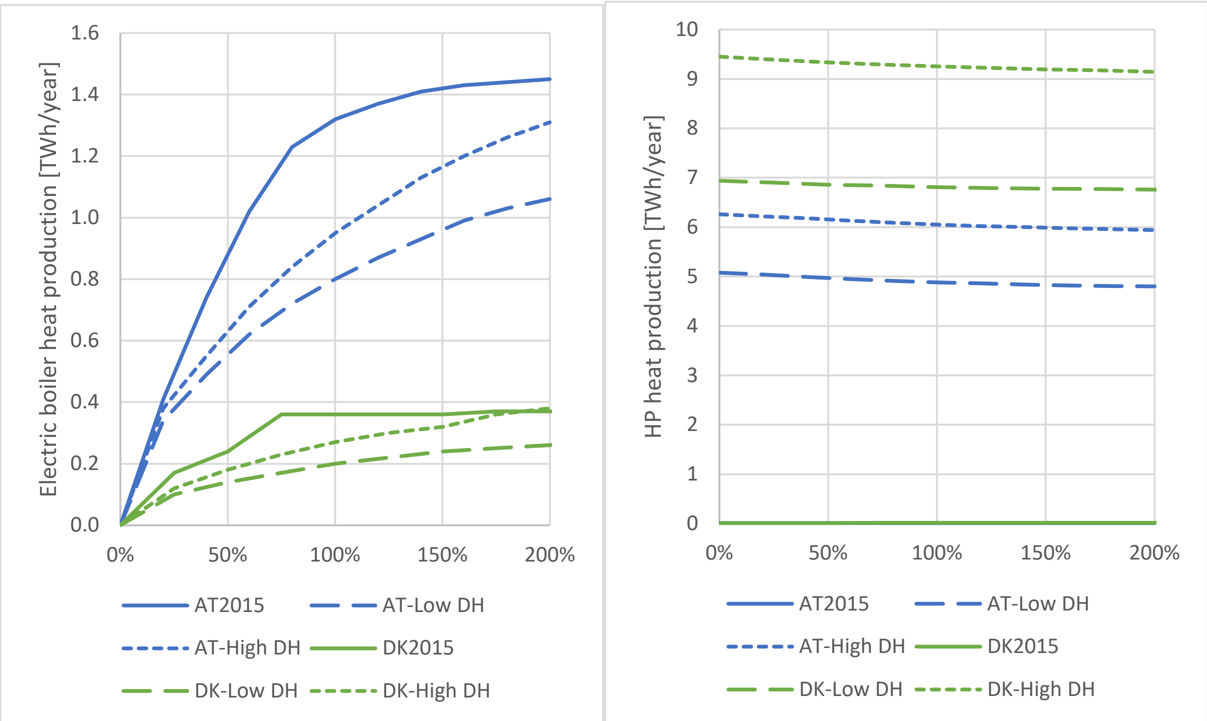

Figure 2: DH production of the electric boilers and HPs in the scenarios. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW electric boiler capacity, and for DK scenarios 100% correspond to 1.5 GW electric boiler capacity.

It can be seen in Figure 2 that changing the electric boiler capacity mostly affects the production of heat on the electric boiler, which mostly replaces the fuel boilers installed in the DH systems. The reason being that the HP is utilised before the electric boiler, due to the higher efficiency of the HP, and the changes that can be observed in the HP operation are caused by the electric boiler using the DH heat storage systems, as the heat produced by the electric boiler can be stored if it cannot be utilised at time of production. It can also be seen that the high DH scenarios allow for more heat production from electric boilers.

Figure 3 shows the change in biomass consumption of the entire energy system. The change is relative to the original scenario.

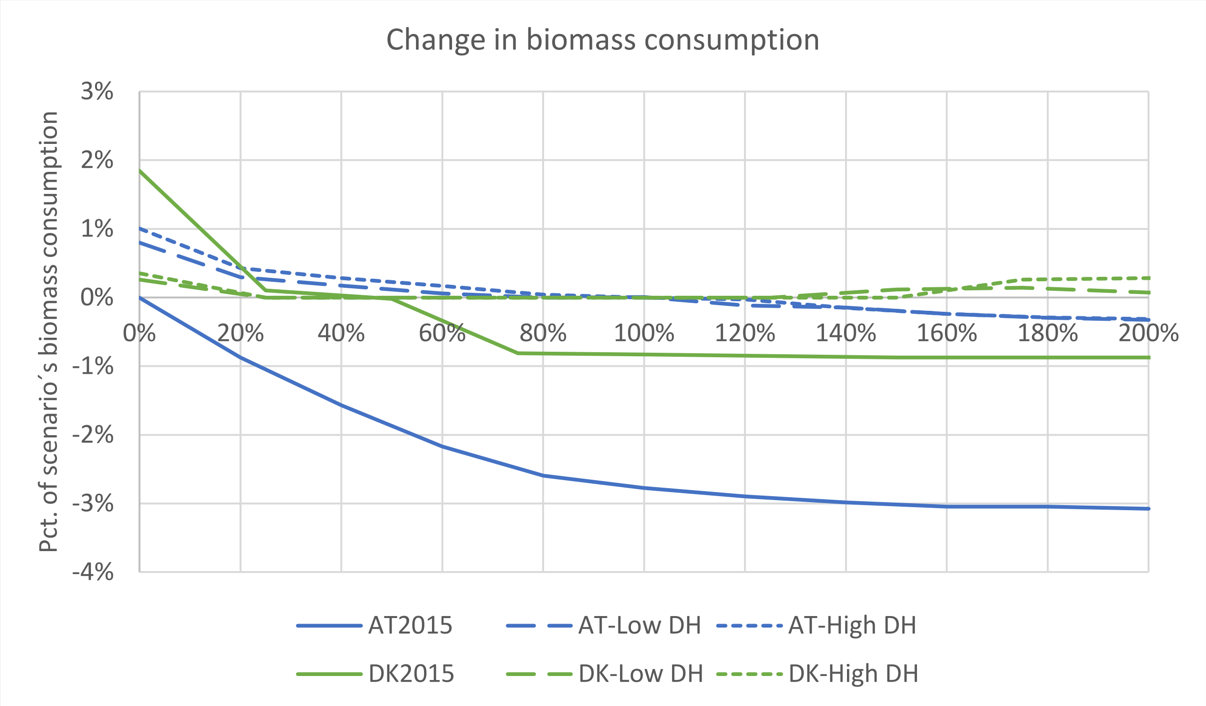

Figure 3: Change in biomass consumption of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW electric boiler capacity, and for DK scenarios 100% correspond to 1.5 GW electric boiler capacity.

As shown in Figure 3 in all scenarios increasing the capacity of electric boilers decrease the biomass consumption of the energy system, as it both allows for integration of increased capacities of variable RES, as shown in Figure 1 but also reduces the biomass consumption for DH fuel boilers. The minor increases for the future DK scenarios are due to a small decrease in CHP operation, as a result of the increasing electric boiler operation filling into the DH storage systems, thereby reducing the utilisation of CHP in certain periods. The missing electricity production is then instead being supplied by condensing operation of the CHP units, in turn resulting in a small increase in gas demand that is fulfilled by increased biomass gasification production.

Figure 4 shows the change in primary energy supply of the entire energy system. The change is relative to the original scenario. The largest relative effect is on the DK2015 scenario, which is directly related to the change in marginal RES production (Figure 1) and biomass consumption (Figure 3). The AT2015 scenario sees an increasing primary energy supply with increasing electric boiler capacity, which is related to the increase in marginal RES production and increase in fossil fuel usage which in total outweighs the reduction in biomass consumption shown in Figure 3.

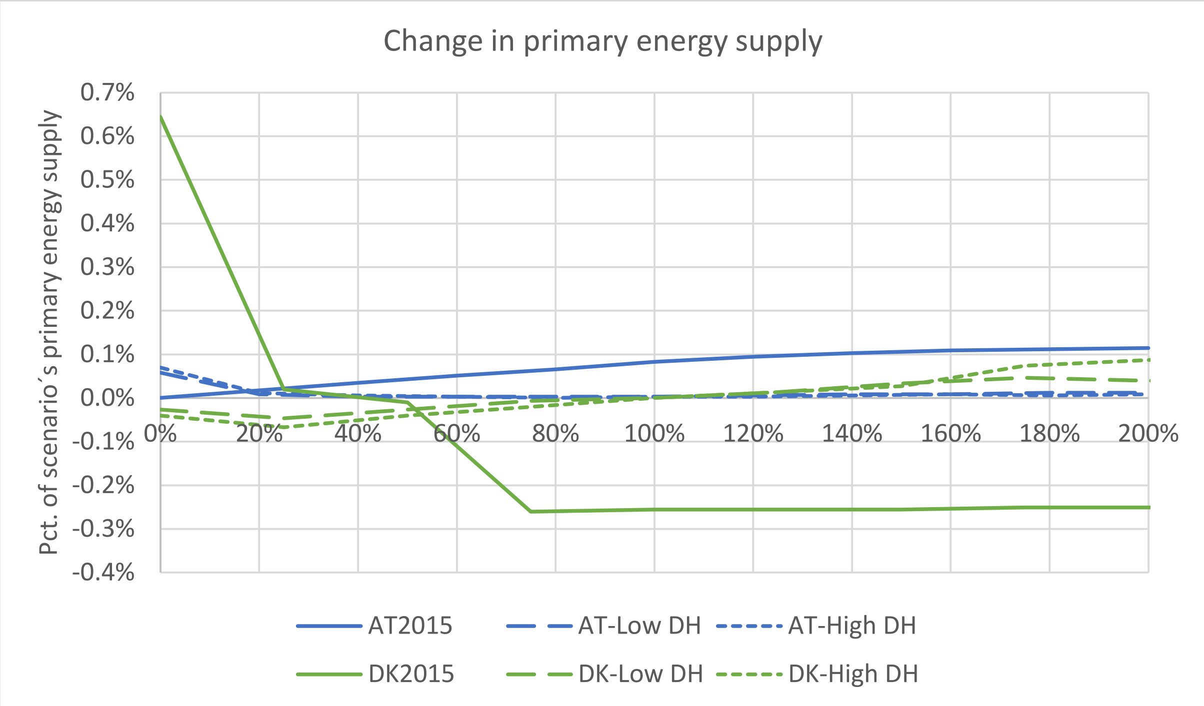

Figure 4: Change in primary energy supply of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW electric boiler capacity, and for DK scenarios 100% correspond to 1.5 GW electric boiler capacity.

Figure 5 shows the change total annual cost of the entire energy system. The change is relative to the original scenario. The effect on the total annual cost of the entire energy system shown in Figure 5 seems to increase with higher levels of electric boiler capacity in the DK scenarios, which for the DK2015 scenario is due to the increase in marginal variable RES capacity and for the future DK scenarios it is because the electric boiler mainly reduces the operation of HPs due to the use of heat storage as described earlier. The opposite effect can be seen for the AT scenarios, where increased electric boiler capacity results in reduced total annual costs, which is due to the electric boilers replacing especially fuel boilers in the DH, which have higher operation costs than HPs.

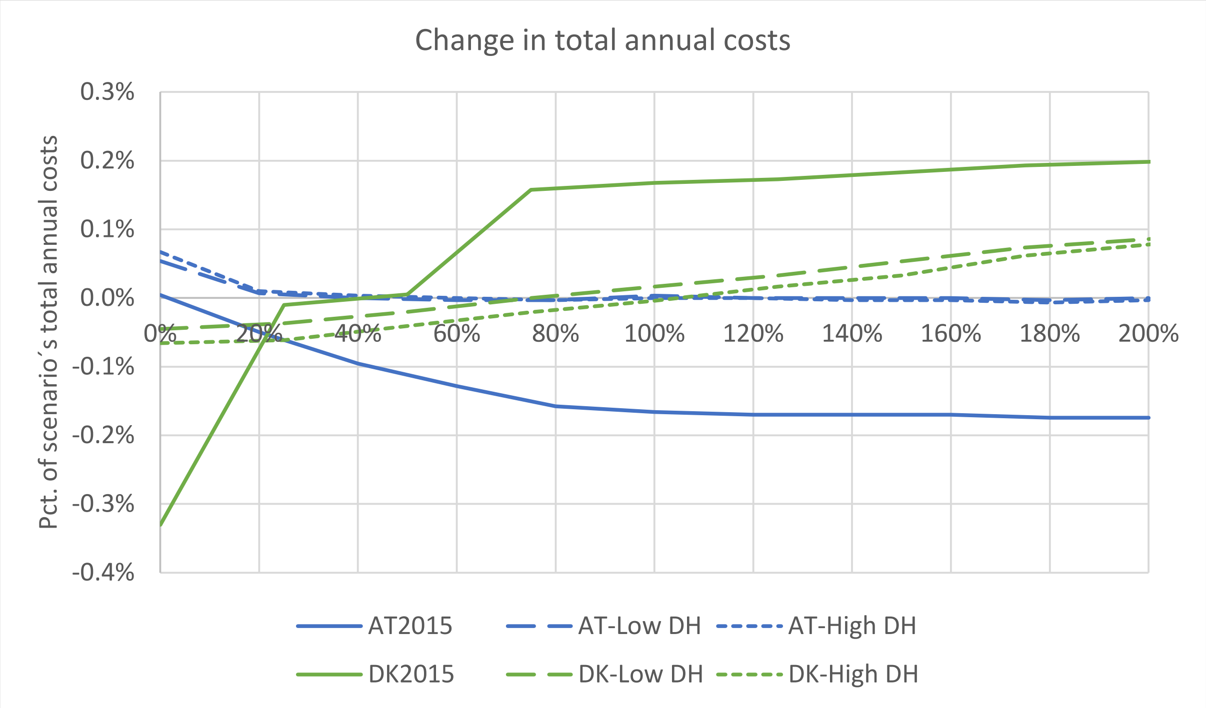

Figure 5: Change in total annual cost of the entire energy system in each scenario The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW electric boiler capacity, and for DK scenarios 100% correspond to 1.5 GW electric boiler capacity.

VARYING LEVELS OF HEAT PUMP CAPACITY IN DISTRICT HEATING

In this section the HP capacity that is connected to DH is changed from 0% to 200% of the initial installed capacity in the future high DH scenario for each country, and the DH electric boiler capacity is kept unchanged. For Austria this means that 100% correspond to 1.2 GW_e HP capacity, and for Denmark 100% correspond to 2.3 GW_e HP capacity.

The changes in the marginal variable RES production are shown in Figure 6. The change in marginal variable RES production is relative to the production in the original scenario, and the different levels of HP capacity are relative to the original high DH scenario for each country.

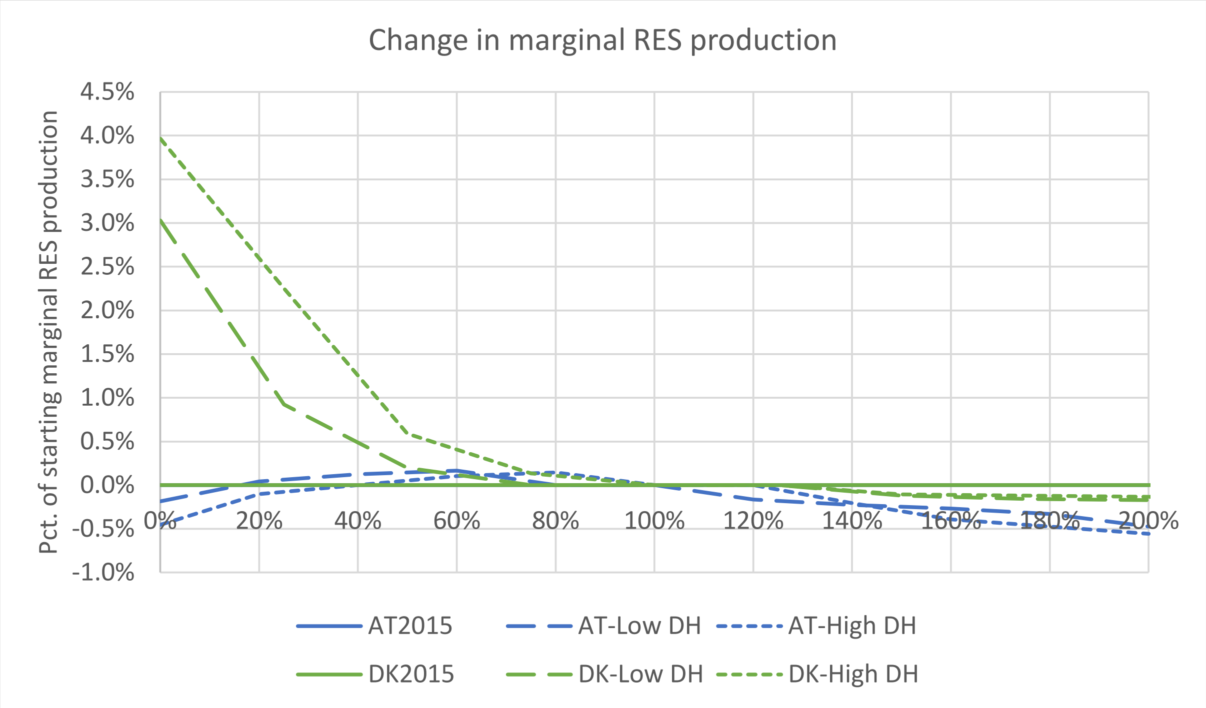

Figure 6: The change in marginal RES production for each of the different scenarios. For AT the marginal RES production is PV and for DK it is offshore wind power. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Generally, change to the HP capacity shown in Figure 6 allows for lower integration of marginal variable RES than when changing the electric boiler capacity, due to the lower efficiency of the electric boiler, as the HP thereby to a larger extend is limited by the DH demand available.

Figure 7 shows the heat production of electric boilers and HPs at different levels of HP capacity relative to the original high DH scenario of the country. It can be seen from the figure that changing the HP capacity affects both the production of heat on the HP and the electric boiler with increasing levels of HP decreasing the electric boiler production, except for AT2015 that has no electric boiler capacity. The high DH scenarios allow for more production on the HP and therefore allow for a higher capacity to be installed before the heat production levels out.

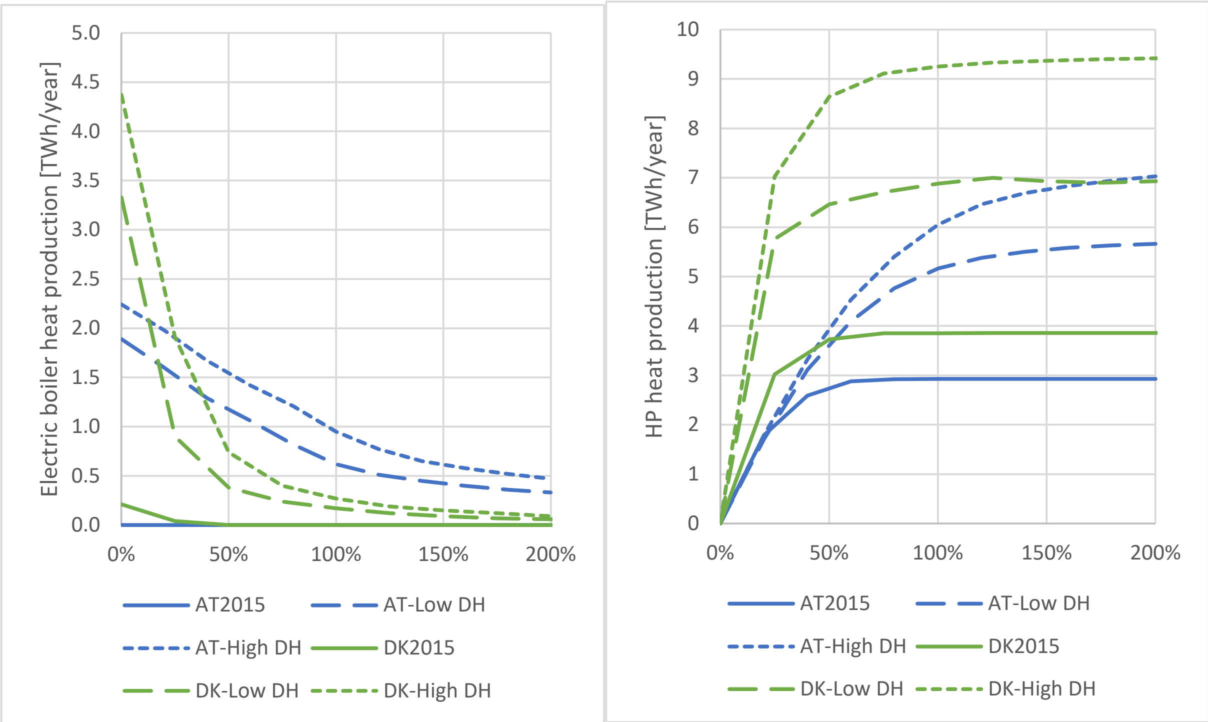

Figure 7: DH production of the electric boilers and HPs in the scenarios. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Figure 8 shows the change in biomass consumption of the entire energy system. The change is relative to the original scenario.

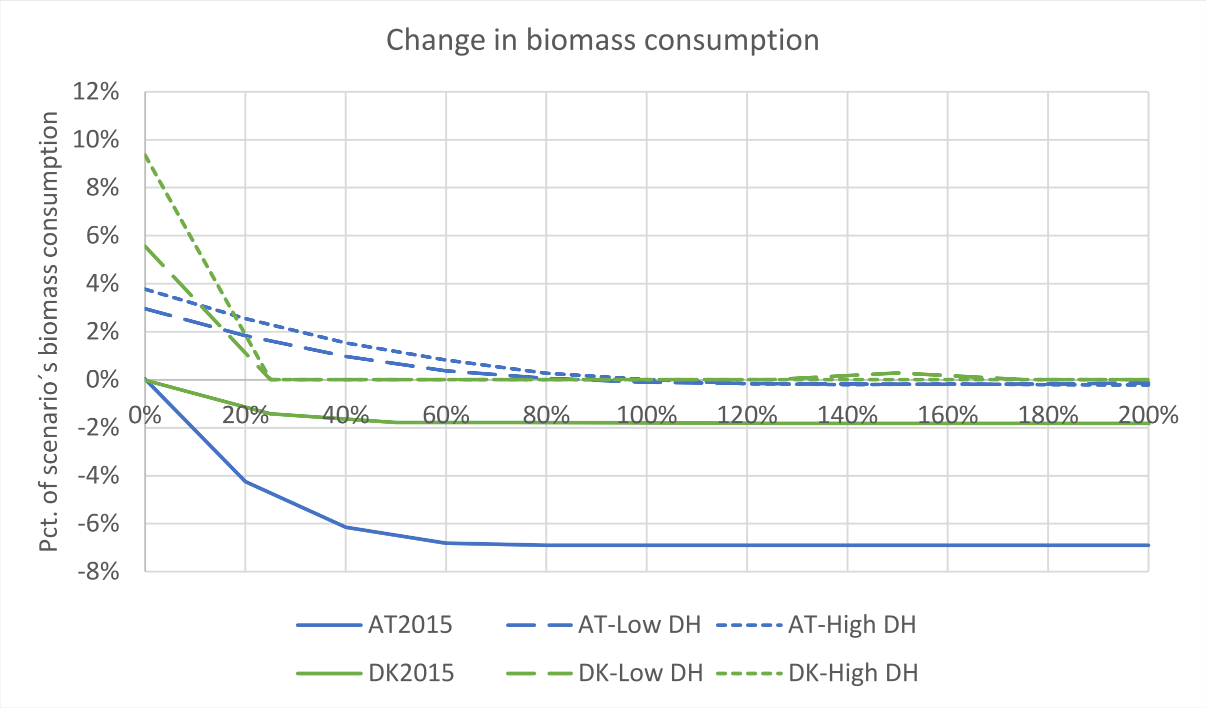

Figure 8: Change in biomass consumption of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

As shown in Figure 8 the biomass consumption is reduced by larger HP capacities, though only until the HP production levels out, as shown in Figure 7. The drop in biomass consumption is larger for HP than was found for change to electric boiler capacity shown in Figure 3. The biomass consumption of the future high DH scenarios is relatively more affected by the change in HP capacity than their low DH counterparts. The future DK scenarios are generally more affected by the change in HP capacity, which is directly related to the change in marginal variable RES shown in Figure 6, where the future DK scenarios also see a larger effect on the installed marginal variable RES, than the AT scenarios, which especially is due to the more flexibility options in the AT scenarios' electricity supply.

Figure 9 shows the change in primary energy supply of the entire energy system. The change is relative to the original scenario.

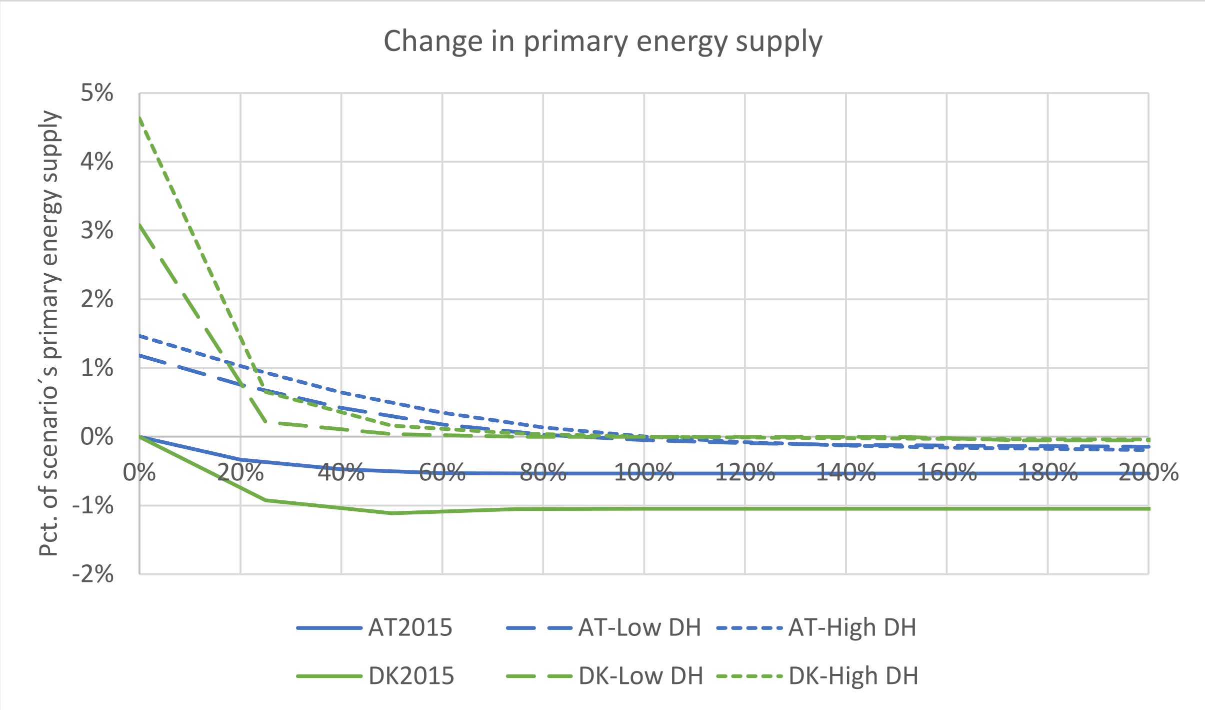

Figure 9: Change in primary energy supply of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

The primary energy supply shows for most scenarios the same tendencies as shown for the biomass consumption shown in Figure 8, except for the 2015 scenarios as these also have fossil fuels in their fuel mix. Though, all scenarios see a decrease in primary energy supply with increasing capacity of HPs in DH. However, this is only until when adding more capacity do not result in increased heat production from the HPs, due to the limited DH demand in the scenarios.

Figure 10 shows the change total annual cost of the entire energy system. The change is relative to the original scenario.

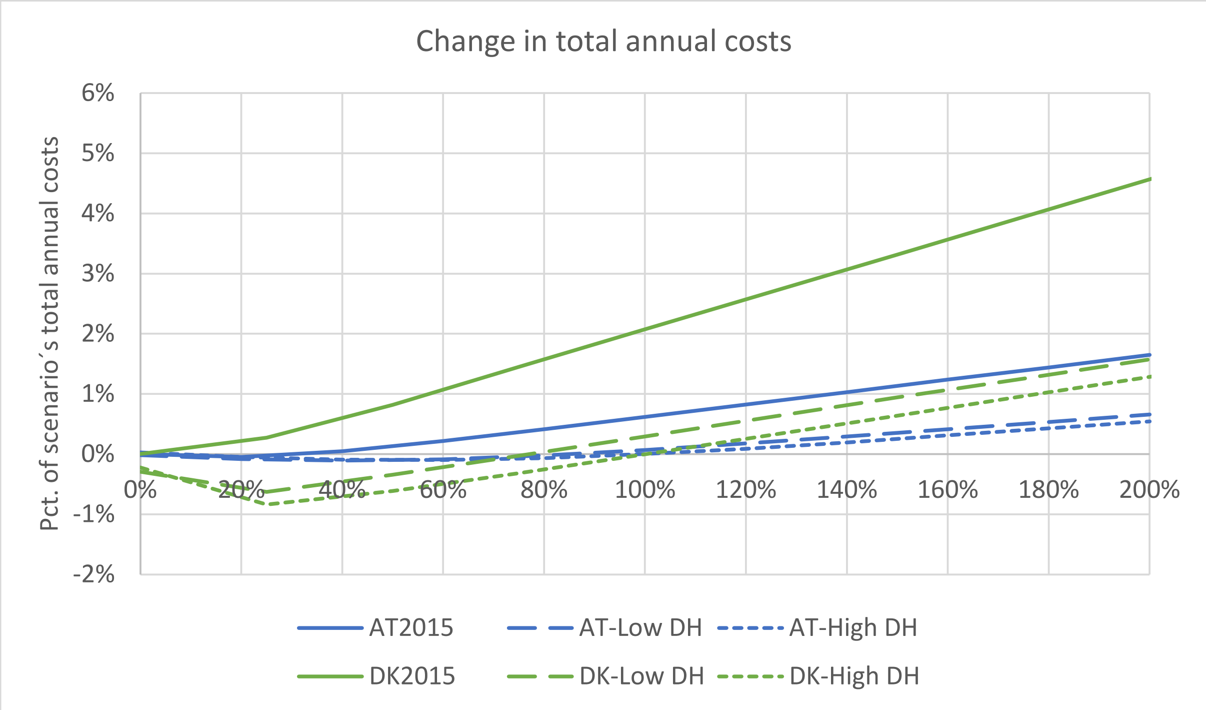

Figure 10: Change in total annual cost of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Cost-wise it is clear from Figure 10 that having some capacity of HP in DH in the energy system allows for reduced energy system costs, but only to an extent, whereafter the costs increase, which is directly related to the utilisation of the installed capacity of HP. For the future DK scenarios this optimum for HPs seems to be around 2,500-3,500 full load hours and for the AT scenarios around 1,500-2,000 full load hours, though as in the AT scenarios the full load hours never go above 2,000 and, in the DK, never above 3,500, these number have a high degree of uncertainty. The effect for HP is more significant than of electric boilers, as the investment cost of HPs are significantly higher than for electric boilers. The energy system costs for the 2015 scenarios are relatively more affected by this, due to lower HP COP alongside higher costs for HPs and the marginal variable RES technology used, compared with the future scenarios.

REPLACING HEAT PUMP AND ELECTRIC BOILER CAPACITY IN DISTRICT HEATING

In this section the HP capacity that is connected to DH is changed from 0% to 200% of the initial installed capacity in the future high DH scenario for each country, like the previous section, though here the DH electric boiler capacity is also changed according to the change in HP electric capacity. Meaning that when the HP electric capacity is reduced then the electric boiler capacity is increased by the same capacity, and vice versa. The electric boiler capacity is limited to zero in capacity, as at high levels of HP capacity the increase in HP capacity in some scenarios is larger than the starting capacity for electric boilers.

The change in the marginal variable RES production are shown in Figure 11. The change in marginal variable RES production is relative to the production in the original scenario, and the different levels of HP capacity are relative to the original high DH scenario for each country.

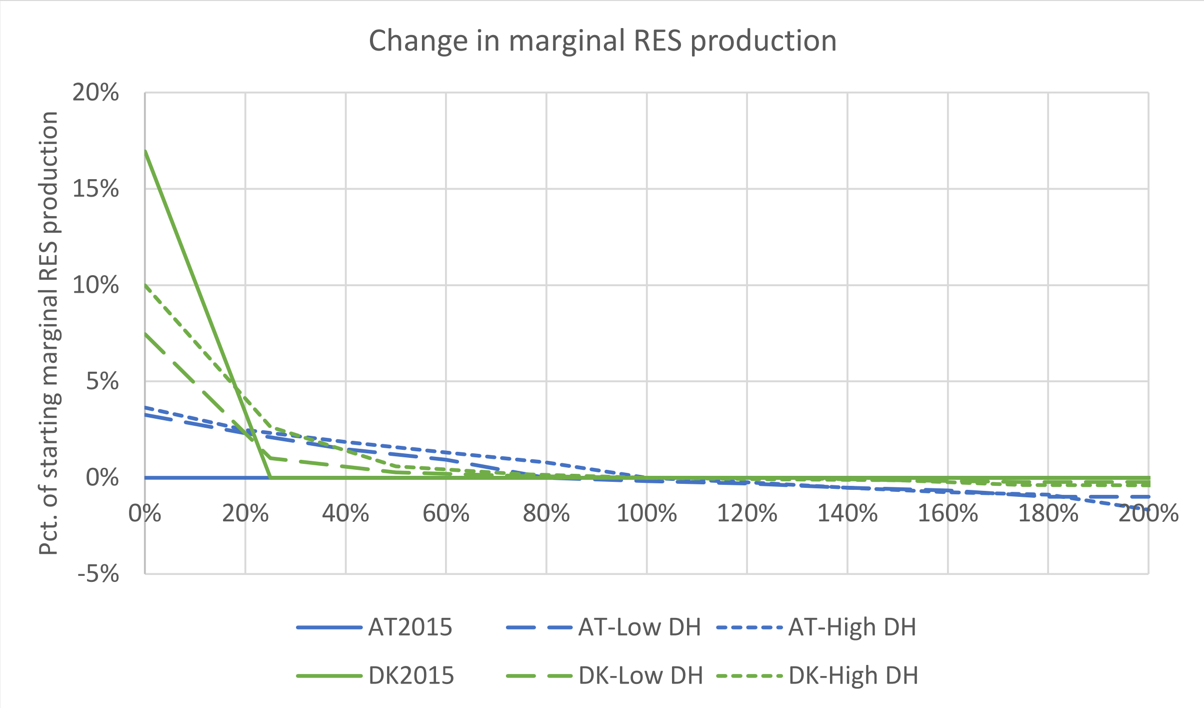

Figure 11: The change in marginal RES production for each of the different scenarios. For AT the marginal RES production is PV and for DK it is offshore wind power. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

As shown in Figure 11, increasing the HP capacity, and thereby also reducing the electric boiler capacity, results in reduced potential to integrate the marginal variable RES, which confirms what was found in the previous sections, that electric boiler capacity generally allows for a larger integration of the variable RES, due to its lower efficiency.

Figure 12 shows the heat production of electric boilers and HPs at different levels of HP capacity relative to the original high DH market share scenario of the country with electric boiler replacement.

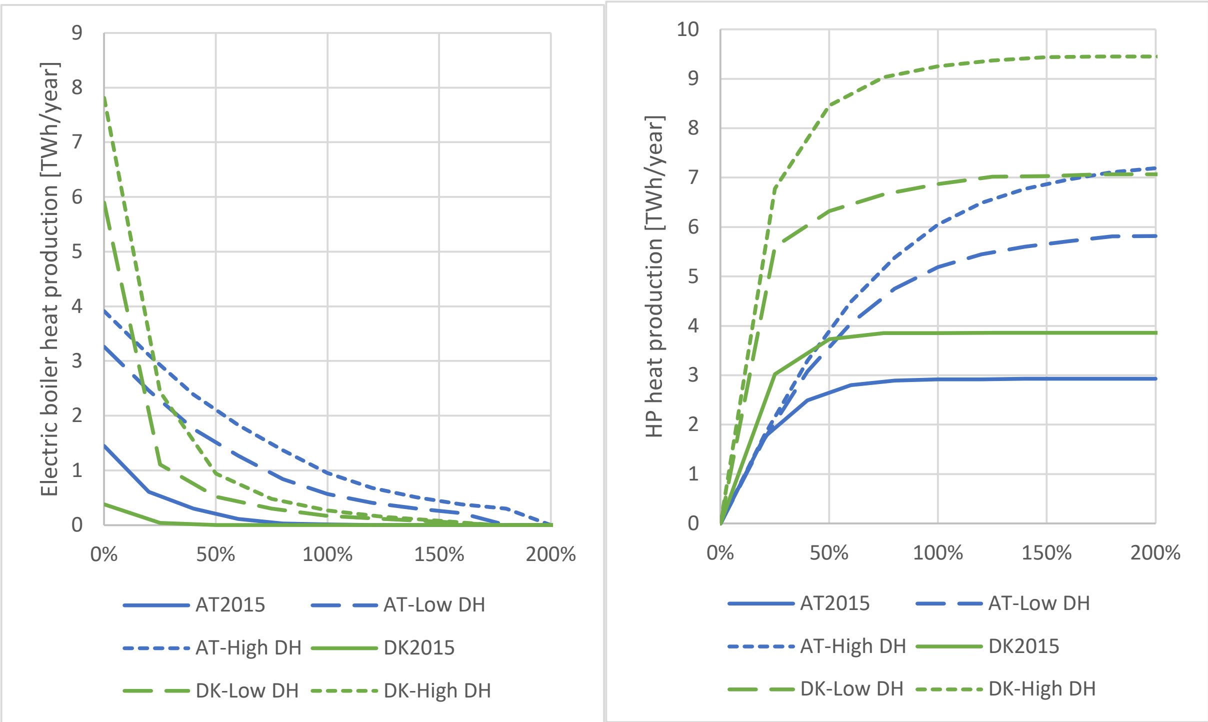

Figure 12: DH production of the electric boilers and HPs in the scenarios. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Figure 12 shows similar effects as was shown in Figure 7, where only the HP capacity was changed, though here the effects are a little more significant as e.g., at higher levels of HP capacity, here the electric boiler capacity is either completely removed or significantly reduced, allowing more heat produced via HPs.

Figure 13 shows the change in biomass consumption of the entire energy system. The change is relative to the original scenario.

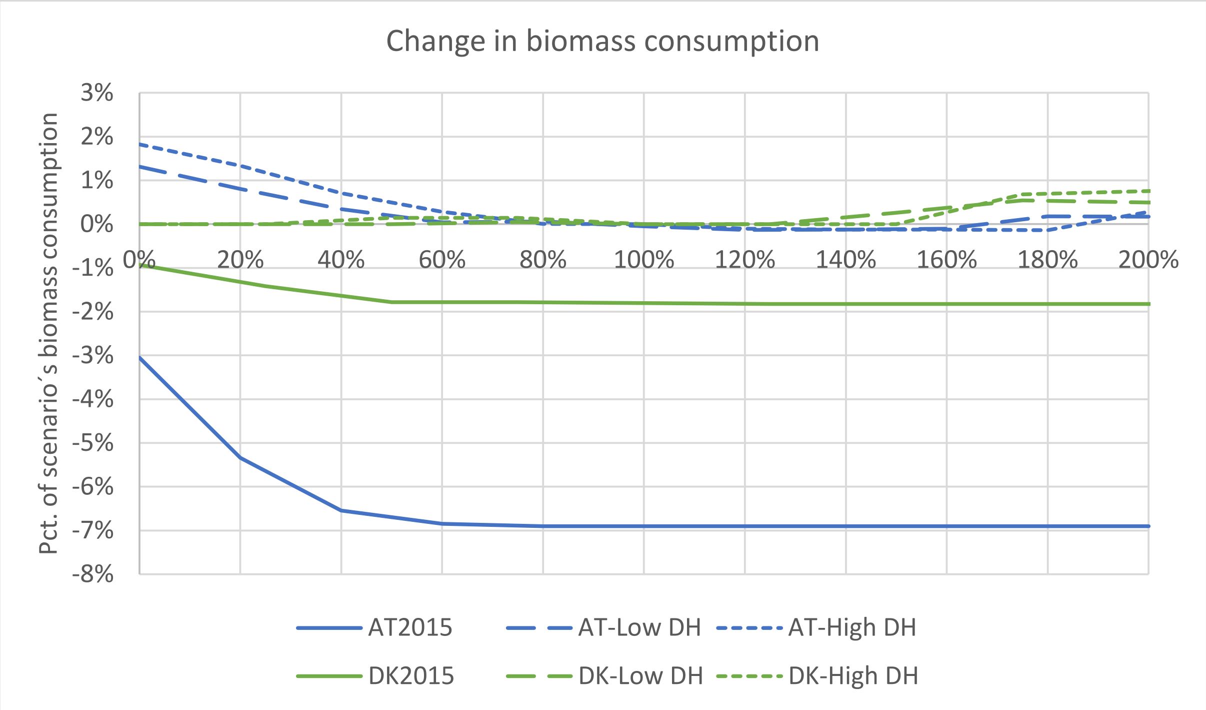

Figure 13: Change in biomass consumption of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Figure 13 shows results like those in Figure 8, where only the HP capacity was changed, indicating that the largest effect on these is the implementation of the HP capacity, with the electric boilers having a significantly lower effect. Similar conclusions can be found for the primary energy supply, shown in Figure 14 that also have similar results as those in Figure 9 where only the HP capacity was changed.

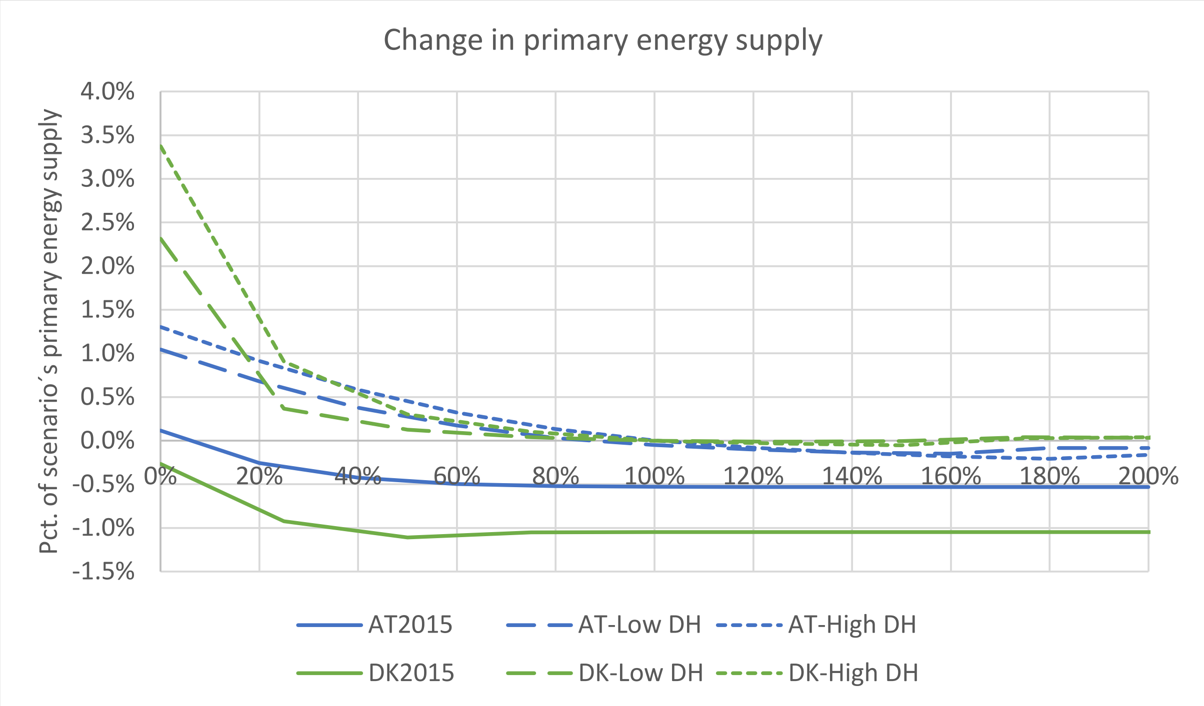

Figure 14: Change in primary energy supply of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

Figure 15 shows the change total annual cost of the entire energy system. The change is relative to the original scenario. Again, the results for changing both the HP and electric boiler have similar outcome as results with only changing the HP. Figure 15 shows results like those in Figure 10, where only the HP was changed, indicating that the largest effect on these is the implementation of the HP capacity, with the electric boilers having a significantly lower effect.

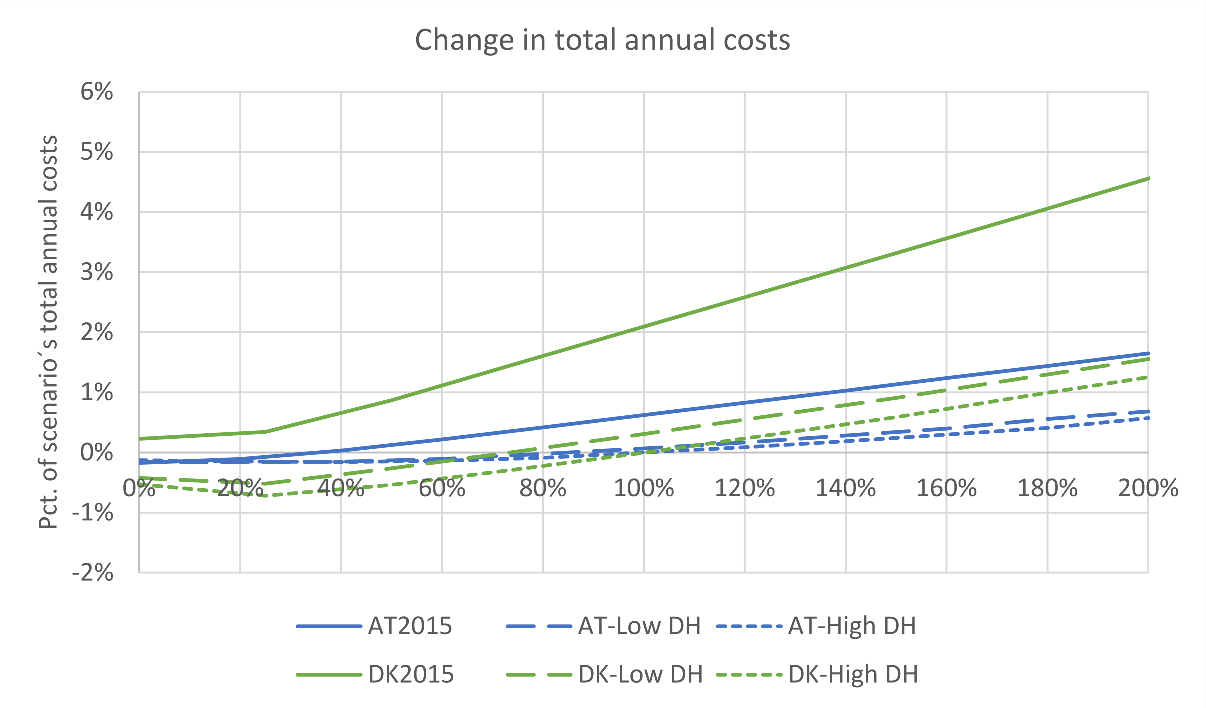

Figure 15: Change in total annual cost of the entire energy system in each scenario. The x-axis shows the installed electric boiler capacity. For the AT scenarios 100% on X-axis correspond to 1.2 GW_e HP capacity, and for DK scenarios 100% correspond to 2.3 GW_e HP capacity.

THERMAL PLANT TECHNOLOGIES

In this section different thermal plant technologies are evaluated.

CHANGE ALL EXISTING LARGE-SCALE CHP TO OTHER TECHNOLOGY

In this section three different large-scale CHP technologies are examined in their relation to the different energy system setups.

Large-scale CHP plants are especially utilised in the AT scenarios, whereas changing the type of technology can have a significant impact on the fuel consumption of the entire energy system, both in terms of amounts but also in type. As the marginal RES production unit for AT is PV that has relative low production in the winter period, and the H_2 storage is sized for weekly storage and not seasonal, then adding significantly more gas production via CO_2 methanation would in turn result in large increase in demand for electricity in the winter period. This electricity demand would then have to be supplied to a large extend by thermal plants, which for gas-fired thermal plant technologies would result in increased gas demand. This means that unless each conversion unit is very efficient, then using this gas balance method will never be able to achieve the same level of yearly net gas import but will instead simply increase the gas demand. Therefore, CO_2 methanation will not be used as an alternative to biomass gasification for the AT scenarios. However, as the DK scenarios have significant less use of large-scale CHP plants, that are already gas-fired and the marginal RES production unit is offshore wind power, that has a more even production throughout the year, then CO_2 methanation can be used for discussing the effects of using this alternative gas balance technology on the DK scenarios.

Figure 16 shows the marginal RES production technology for each of the different scenarios with different large-scale CHP technologies. The difference between each CHP technology used is solely related to the change in capacity.

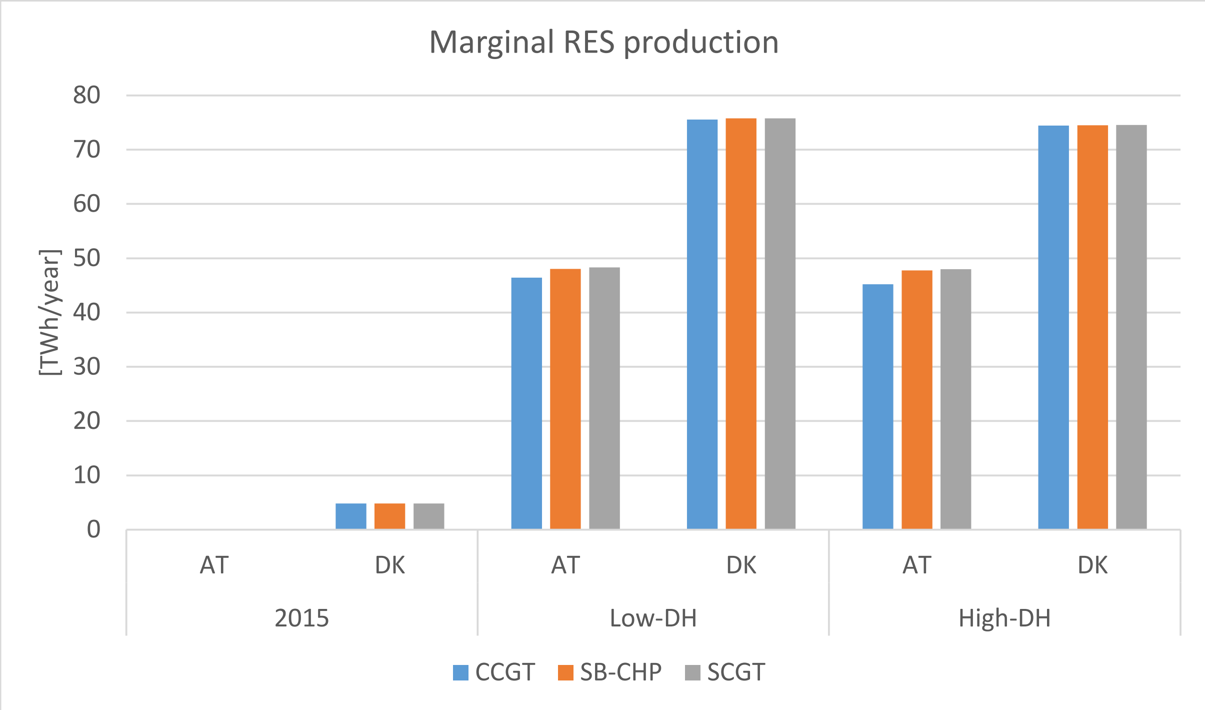

Figure 16: The marginal RES production for each of the different scenarios. For AT the marginal RES production is PV and for DK it is offshore wind power.

As shown in Figure 16 the effect on the marginal RES production is similar for all the technologies, though the CCGT technology provide the lowest need for marginal RES production. The effect is largest for the future AT scenarios with a reduction in marginal RES production of 2 TWh compared to the starting point of the low-DH scenario and a reduction of 3.2 TWh in the high-DH scenario. This is compared with a reduction for the other technologies of 0.1-0.4 TWh in the low-DH scenario and 0.5-0.7 TWh in the high-DH scenario. The effect is largest in the AT scenarios due to the larger utilisation of CHP compared with the DK scenarios, though a similar effect is seen in the DK scenarios where the CCGT result in a reduction of 0.38 TWh in the low-DH scenario compared with a reduction of the other technologies of 0.16 TWh, and a reduction of 0.23 TWh in the high-DH scenario compared with 0.12-0.17 TWh for the other technologies.

If instead CO_2 methanation was used for the DK scenarios, then the SB-CHP technology would result in large decreases in need for marginal RES production. The reason is that the existing large-scale CHP technologies in the future DK energy system are gas-fired SCGT and CCGT, where part of the gas demand are satisficed via gaseous electrofuels that consume a significant amount of electricity. By changing all these gas-fired CHP units to be solid biomass, then the demand for gaseous electrofuels decreases and thereby the need for the marginal RES production. Likewise, opposite to the biomass gasification approach where excess heat from the production of gas process is not included, when using the CO_2 methanation, the electrolysers are used more extensively due to increased H_2 demands, meaning that a larger amount of excess heat is produced from the electrolysers, which in turn leaves less potential for utilising HPs and electric boilers to utilise CEEP. With CO_2 methanation CCGT also has a lower need for marginal RES production compared with the other gas-fired technology, mainly SCGT. The reason is that the CCGT has a higher electric efficiency which is more valuable to the energy system than the higher heat efficiency of the SCGT, and thereby the need for gaseous electrofuels is lower for the CCGT than the SCGT.

Figure 17 shows the primary energy supply for the entire energy system with different large-scale CHP technologies in each of the scenarios.

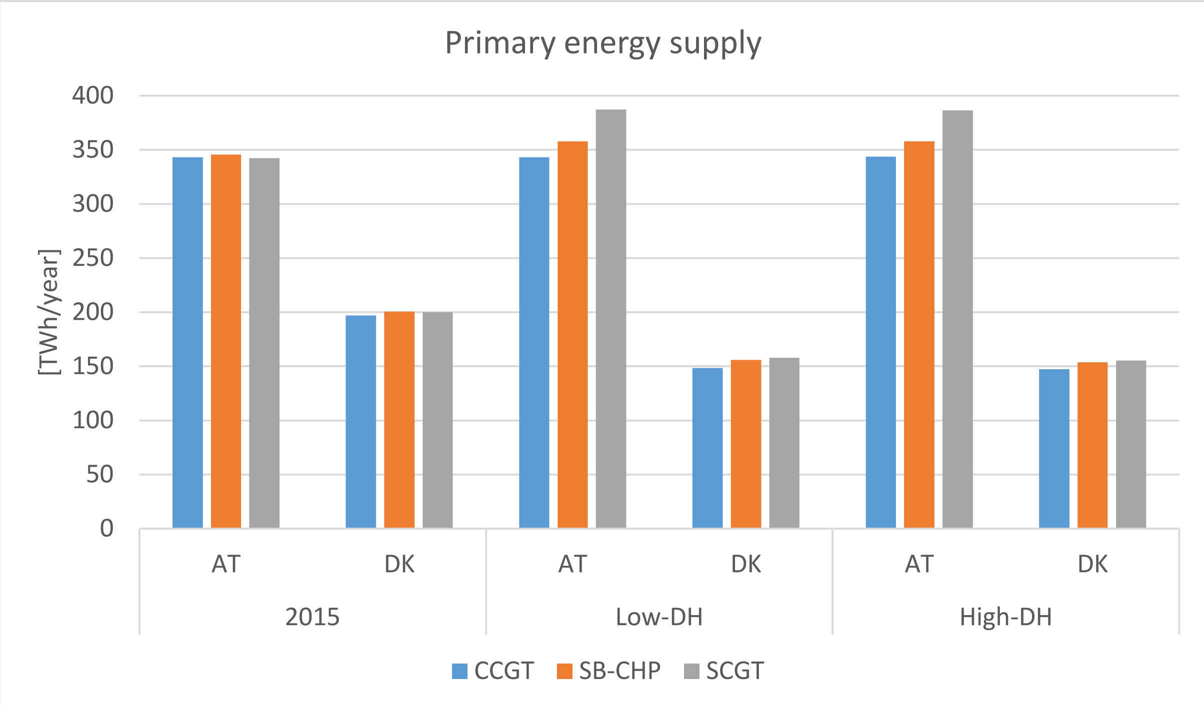

Figure 17: Primary energy supply of the entire energy system in each of the different scenarios

As shown in Figure 17 the primary energy supply is similar between the three technologies in the 2015 scenarios. In the AT 2015 scenario the lowest primary energy supply is with the SCGT technology and in DK 2015 it is the CCGT technology. The reason for the difference is the need for thermal plant operation to meet the electricity demand, where thermal plants with higher heat efficiency in the DK 2015 system will operate more in condensing mode than a plant technology with a lower heat efficiency, as the DH demand sets the limit for CHP utilisation. This is not to the same case the effect in the AT 2015 scenario where there is dispatchable hydro power, which in turn means that it is the need for thermal plants in the electricity sector that sets the limit for the thermal plant operation, where with lower heat efficiency of the thermal plant technology the large-scale CHP will not operate more or less, but simply deliver less heat for DH, which instead are being provided by fuel boilers. In the future scenarios CCGT provides the lowest primary energy supply in all scenarios. The effect is, however, greatest in the AT scenarios where there is a larger utilisation of the large-scale CHP units and thereby more significant effect of the change of CHP technology.

If instead CO_2 methanation was used for the future DK scenarios, then the primary energy supply for CCGT and SB-CHP would instead be at the same level, and both would be the lowest of the three technologies, even though the CCGT have a significantly higher electric efficiency. The reason for this is the conversion losses in the production of gaseous electrofuels, requiring more wind power in the system, resulting in the same level of primary energy supply. The SCGT would in this case have the highest primary energy consumption, due to it experiencing the same conversion losses for production of electrofuels while having a lower electric efficiency than the CCGT, and thereby a lower total efficiency.

However, as to better assess the effect on the primary energy supply it is important to also consider the effect of import and export of gas to the energy system. Figure 18 shows the difference in yearly net gas import compared to the net gas import in the starting scenario. As such, if the net gas import is negative that means that less gas is imported, and vice versa.

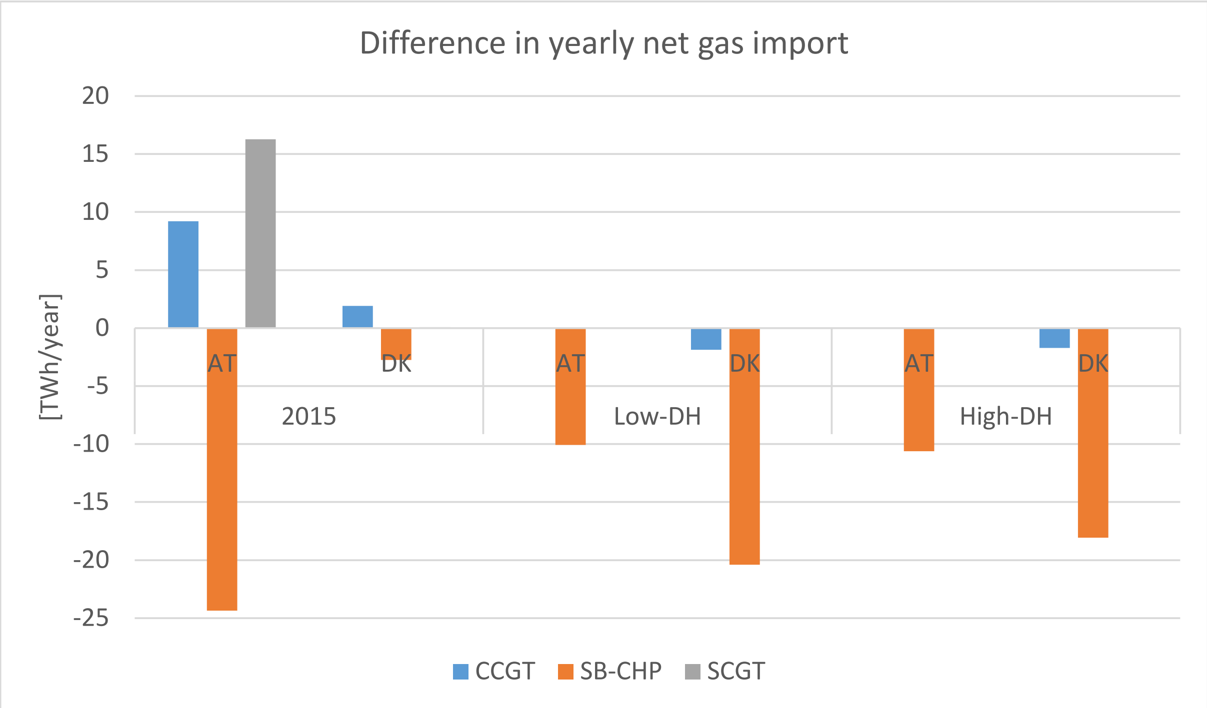

Figure 18: Difference in yearly net gas import compared to starting scenario.

As shown in Figure 18 the yearly net gas import is never positive in the future scenarios, which is because in cases where the gas need increases, this is met by an increase in the internal production of gas via biomass gasification. In all scenarios changing technology to SB-CHP decreases the yearly net gas import, meaning that there is a lower demand for gas in the energy system, and as no starting scenario has gas production via biomass gasification, reducing the need of gas directly results in reduced import of gas. The CCGT also result in reduced need for gas consumption in the future scenarios, though to a much lesser extent and mostly in the DK scenarios, where it replaces a mix of SCGT and CCGT.

Figure 19 shows the biomass consumption for the entire energy system with different large-scale CHP technologies in each of the scenarios.

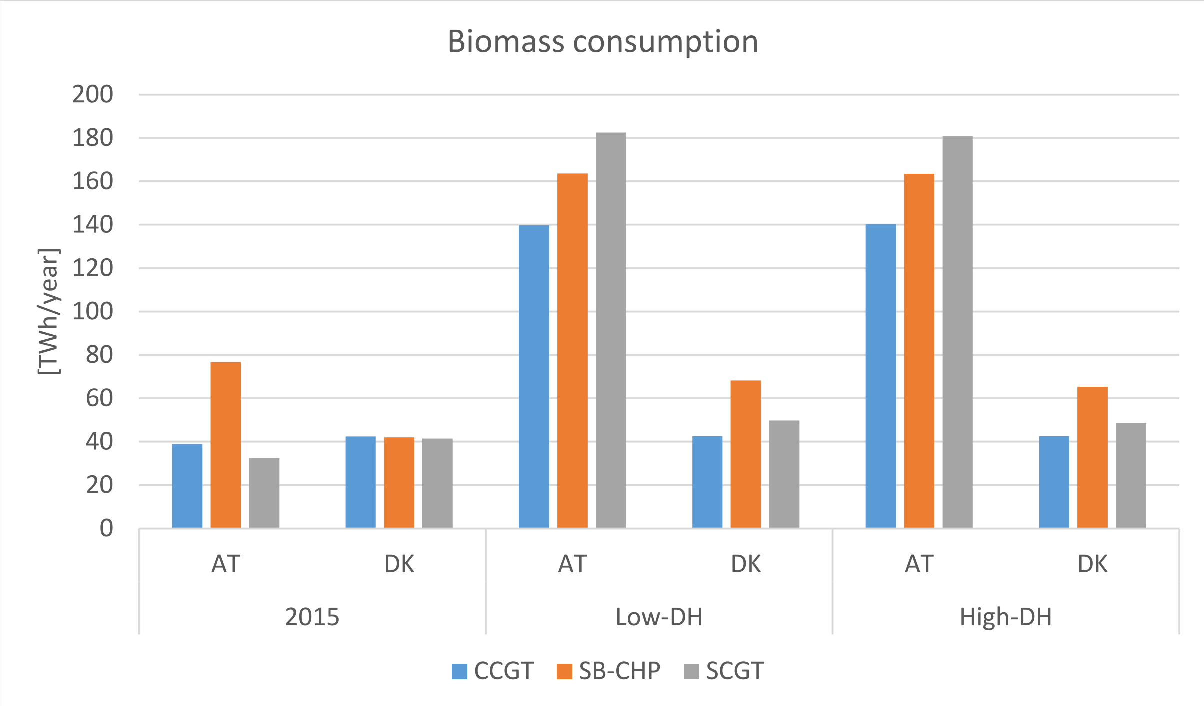

Figure 19: Biomass consumption of the entire energy system in each of the different scenarios

As shown in Figure 19 in the AT 2015 and future DK scenarios the biomass consumption is highest for the SB-CHP technology, and only the second highest for the other scenarios. For the AT2015 scenario this is because the SB-CHP directly utilise biomass whereas the fuel boilers which is the alternative DH production in AT2015 use a mix of biomass and fossil fuels. In the future DK scenarios, the SB-CHP replaces gas fired large-scale CHP technologies, where the CCGT results in a general lower gas consumption than in the starting point and thereby do not need addition of biomass gasification, whereas the SCGT do require more biomass gasification due to increased gas demand, though due to a higher electric efficiency in CHP operation this increase do not affect the biomass consumption as much as occurs with the SB-CHP. In the future AT scenarios, the larger biomass consumption for SCGT is due to increased need for biomass for biomass gasification that especially goes to condensing CHP operation, which in turn means this biomass pathway result in a lower efficiency (80% * 45% = 36%) compared with the SB-CHP condensing operation of 44.8% electric efficiency. The higher electric and lower thermal efficiency of the CCGT technology allows it to operate in CHP mode more, meaning that here the extra conversion loss through the biomass gasification result in a reduction of biomass consumption, as the fuel consumption for condensing CHP operation is only about half of both the SB-CHP and SCGT.

If instead CO_2 methanation was used for the gas balancing in the future DK scenarios, then the biomass consumption of CCGT and SCGT would be the same as in the starting point, namely 42.5 TWh, as this technology do not utilise biomass. The SB-CHP would here increase the biomass consumption to 63 TWh, as when changing from gas-fired units to biomass fired, it is not possible to reduce the fuel consumption by increasing the gas production via CO_2 methanation, unless the biomass in other sectors could be reduced, though this is not considered here.

As to better understand the effects of the fuel consumption, Figure 20 shows the biomass consumption adjusted for the effects on the gas exchange shown in Figure 18. The adjustment is here made using the assumption that any change in gas exchange will result in change in biomass consumption for biomass gasification outside of the modelled country. As such, this adjusted biomass consumption is not for the modelled energy system but includes potential effects outside the modelled energy system and do not include the electricity consumption related to this production. This adjustment is only shown for the future energy systems.

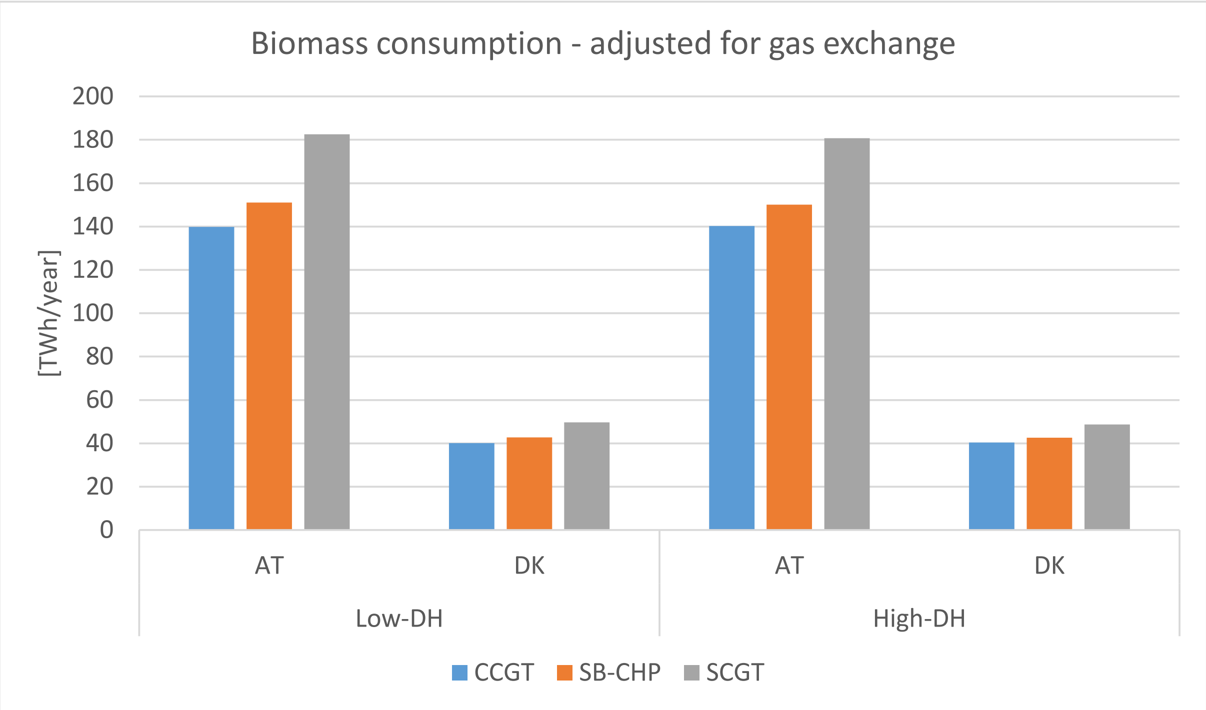

Figure 20: Biomass consumption of the entire energy system in each of the different scenarios. The biomass consumption is adjusted for gas exchange with assumption of biomass gasification as marginal gas producer outside the modelled energy system.

As shown in Figure 20 adjusting for this provide the largest reduction for the SB-CHP technology, as this technology have a large effect on the yearly net import of gas. In the DK scenarios the method result in the SB-CHP technology goes from the highest biomass consumption to the second highest. However, in all cases the CCGT technology continues to show the lowest biomass consumption.

Figure 21 shows the total annual cost for the entire energy system with different large-scale CHP technologies in each of the scenarios.

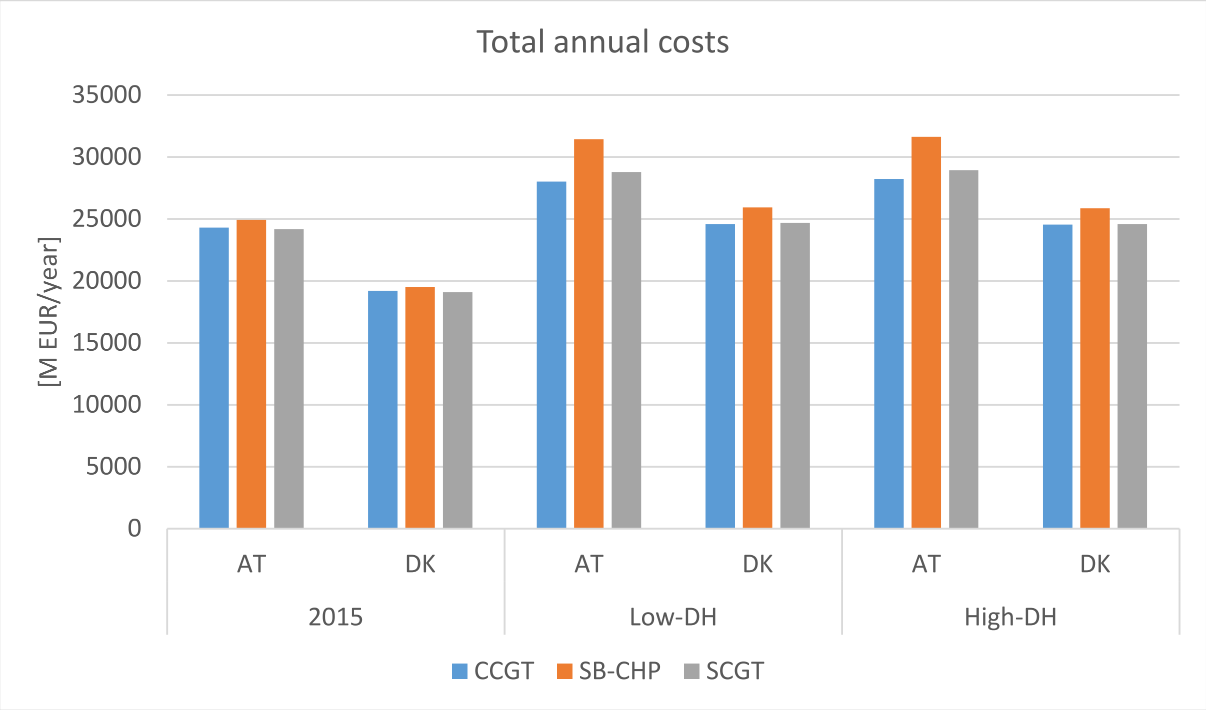

Figure 21: Total annual costs of the entire energy system in each of the different scenarios

As seen in Figure 21 the lowest total annual cost of the entire energy system is found with the CCGT technology in the future scenarios. Compared to the SCGT the increased electric efficiency of the CCGT makes up for its larger investment cost for the technology. The SB-CHP technology shows the highest total energy system costs, which is due to both higher investment cost in the technology but also higher fuel costs. In the 2015 scenarios the lowest costs are found for the SCGT technology. The reason for this is mainly due to the lower investment cost for SCGT than both CCGT and SB-CHP.

NO LARGE-SCALE CHP

In this section the effect of changing all the large-scale CHP plants to power plants, as to see to what effects large-scale CHP plants have on the operation of the energy systems. The same technologies as used in Section 4.1.2.1 are used here, and the effects of removing the large-scale CHP plants are shown as the change compared to the results with large-scale CHP with the same technology. As to make the comparison between scenarios easier, the effect is shown per TWh removed CHP heat production.

Figure 22 shows the change in marginal RES production technology for each of the different scenarios with different no large-scale CHP. The change is shown in TWh removed CHP heat production and it is relative to Figure 16 in Section 4.1.2.1, which shows the marginal RES production where the same technologies are used in large-scale CHP applications. The difference between each CHP technology used is solely related to the change in capacity.

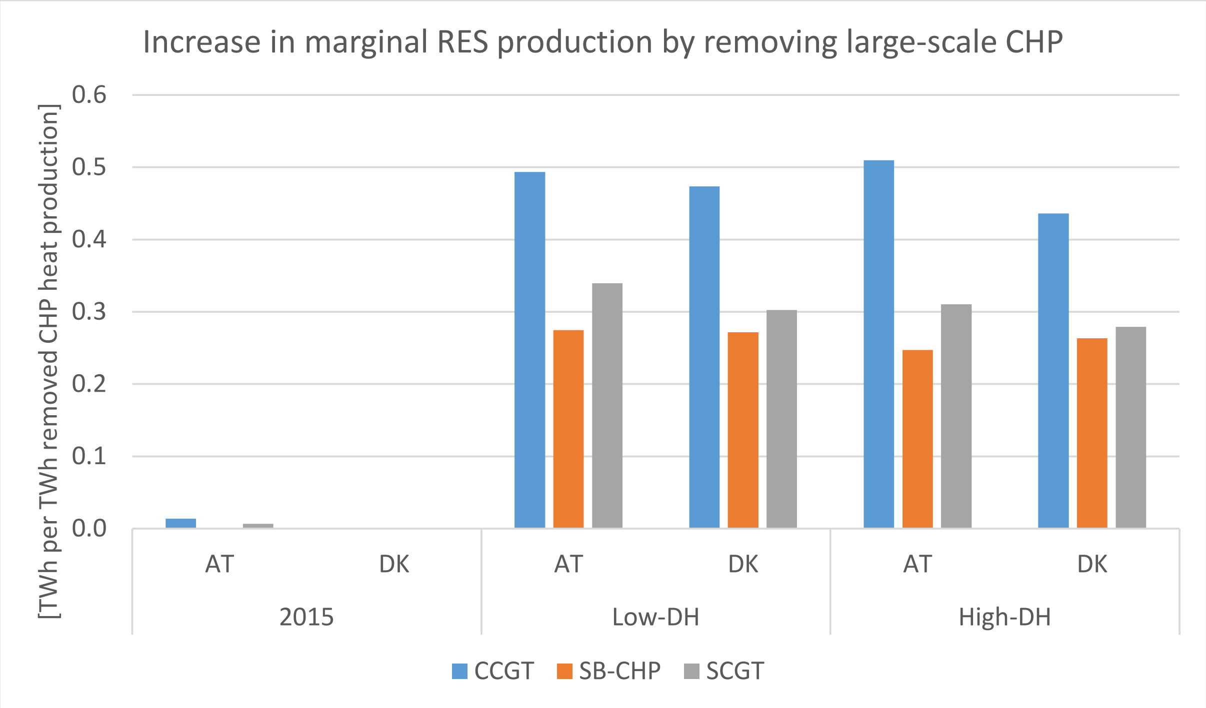

Figure 22: Increase in marginal RES production without large-scale CHP as compared with Figure 16. The increase is expressed per TWh decrease in CHP heat production.

As shown in Figure 22 removing the large-scale CHP capacity in favour of power plant capacity results in increased need for marginal RES production in all the future cases, due to increased use of HP as replacement for the DH that was produced by CHP. The effect is a bit larger for the gas-fired technologies, which is due to their lower DH production from these, which shows due to the increase being expressed by TWh removed CHP heat production.

Figure 23 shows the increase in primary energy supply for the entire energy system with no large-scale CHP, with different thermal plant technologies as power stations in each of the scenarios. The change is shown in TWh removed CHP heat production and it is relative to Figure 17 in Section 4.1.2.1, which shows the primary energy supply where the same technologies are used in large-scale CHP applications.

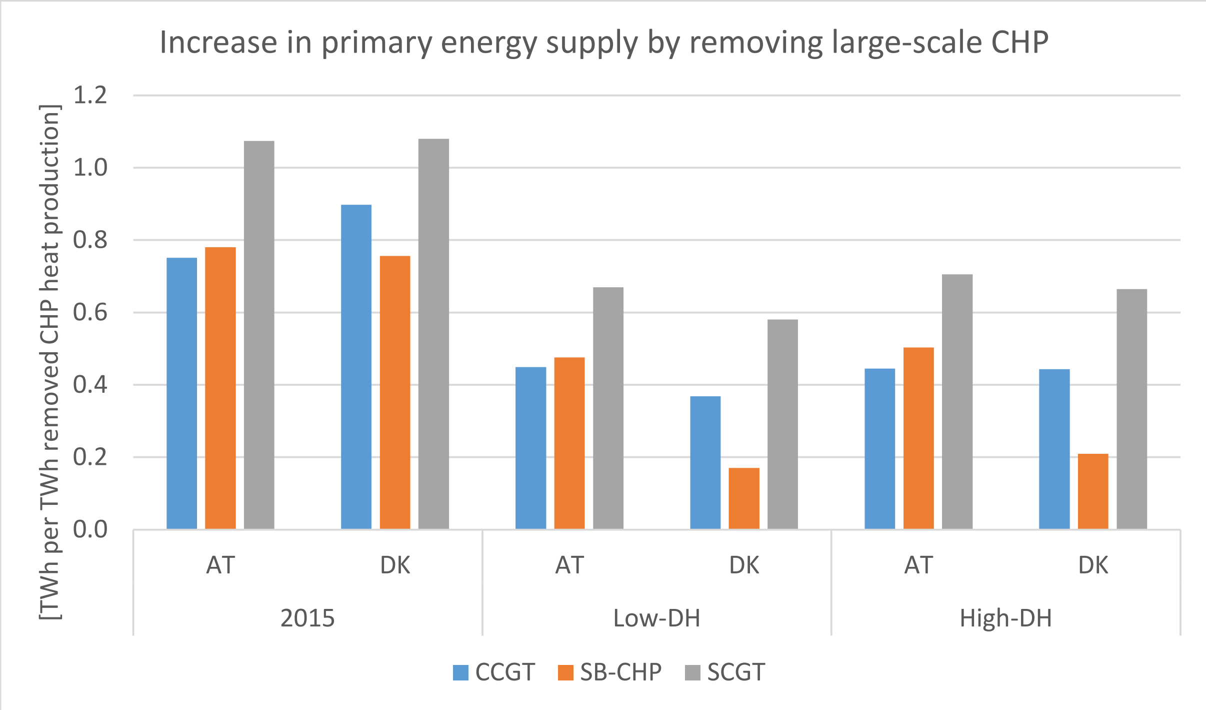

Figure 23: Increase in primary energy supply of the entire energy system without large-scale CHP as compared with Figure 17. The increase is expressed per TWh decrease in CHP heat production.

As shown in Figure 23 replacing the large-scale CHP plants with power plants increases the primary energy supply needed in each scenario. The effects are lowest in the 2050 DK scenarios, as these scenarios have the lowest production of heat from CHP, and as such, it is easier to replace with existing capacities of other energy efficient technologies, mainly HPs. In all scenarios the SCGT technology results in the largest increase per TWh removed CHP heat production, which is due to this technology having the same electric efficiency regardless of whether it is operating as CHP or power plant. In the DK scenarios the increase is lowest for the SB-CHP technology, which is related to it having the largest increase in electric efficiency when operating as a power plant instead of CHP plant.

To better assess the effect on the primary energy supply it is important to also consider the effect of import and export of gas to the energy system. Figure 24 shows the difference in yearly net gas import compared to the net gas import in with large-scale CHP.

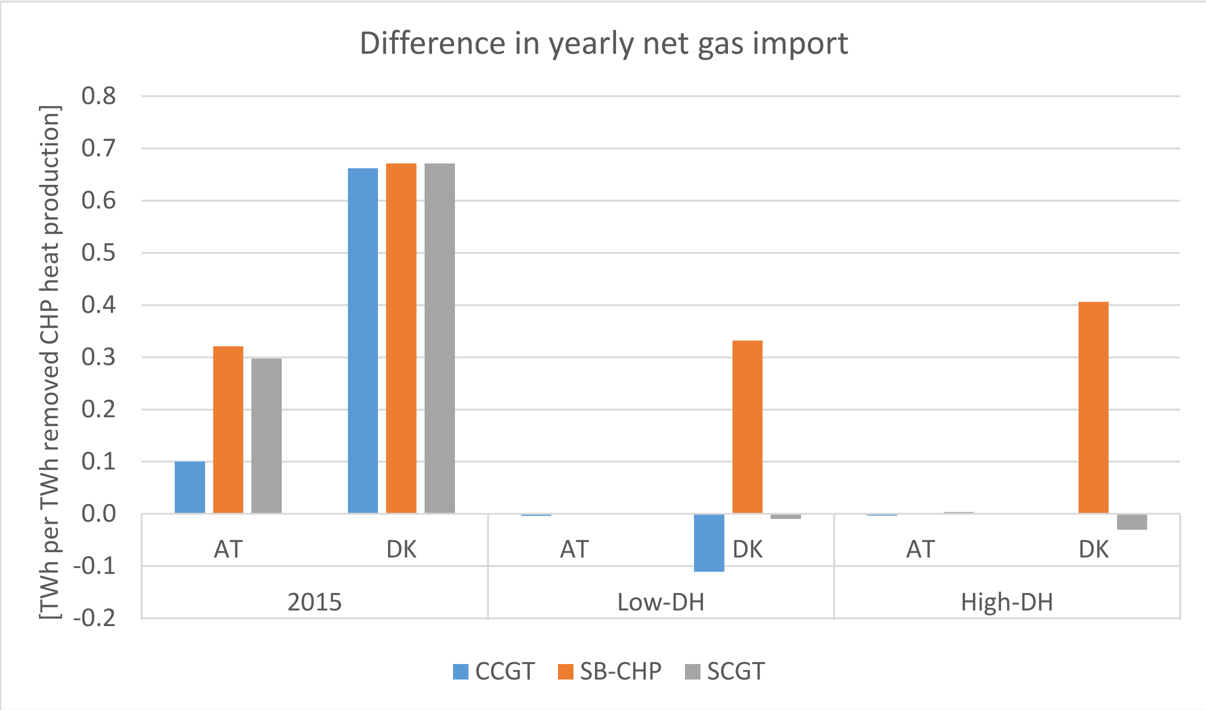

Figure 24: Increase in yearly net gas import without large-scale CHP as compared with Figure 18. The increase is expressed per TWh decrease in CHP heat production.

As shown in Figure 24, generally removing the large-scale CHP capacity increases the yearly net import of gas, though the CCGT technology with low amount of DH in the future DK scenario does show a small reduction in net gas import from the removal of large-scale CHP, which is due to the high electric efficiency of this technology in power plant operation, and a relative large electricity demand for individual HP solutions in buildings without DH.

Figure 25 shows the increase in biomass consumption of the entire energy system with no large-scale CHP, with different thermal plant technologies as power stations in each of the scenarios. The change is relative to Figure 19 in Section 4.1.2.1, which shows the biomass consumption where the same technologies are used in large-scale CHP applications.

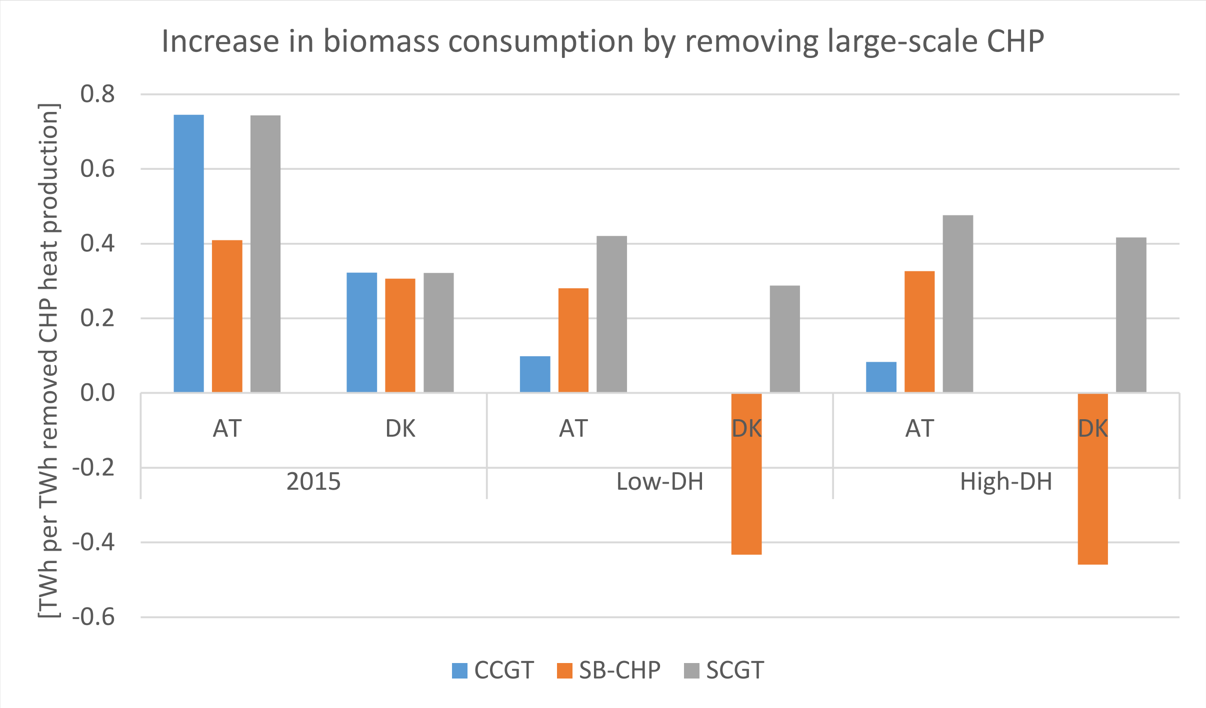

Figure 25: Increase in biomass consumption of the entire energy system without large-scale CHP as compared with Figure 19. The increase is expressed per TWh decrease in CHP heat production.

A shown in Figure 25 replacing the large-scale CHP plants with power plants increases the biomass consumption in all the 2015 scenarios, which is especially due to increased use of biomass-fired fuel boilers to replace the missing heat production from the large-scale CHP plants. For the future DK 2050 scenarios, the gas-fired CCGT solution have similar biomass consumption as with large-scale CHP, which is due to the replacement units being gas-fired fuel boilers and HPs. Interestingly for SB-CHP is that removing the large-scale CHP plant capacity result in decreased use of biomass in the future Danish scenarios. This is because it moves the electricity production from CHP to power plant, which have a higher electric efficiency, and the replacement technologies in the DH system is mostly electric-driven technologies being HPs and electric boilers that combined replace 50-60% of the heat production that the CHP plants would have delivered.

Figure 26 shows the increase in total annual cost of the entire energy system with no large-scale CHP, with different thermal plant technologies as power stations in each of the scenarios. The change is relative to Figure 21 in Section 4.1.2.1, which shows the biomass consumption where the same technologies are used in large-scale CHP applications.

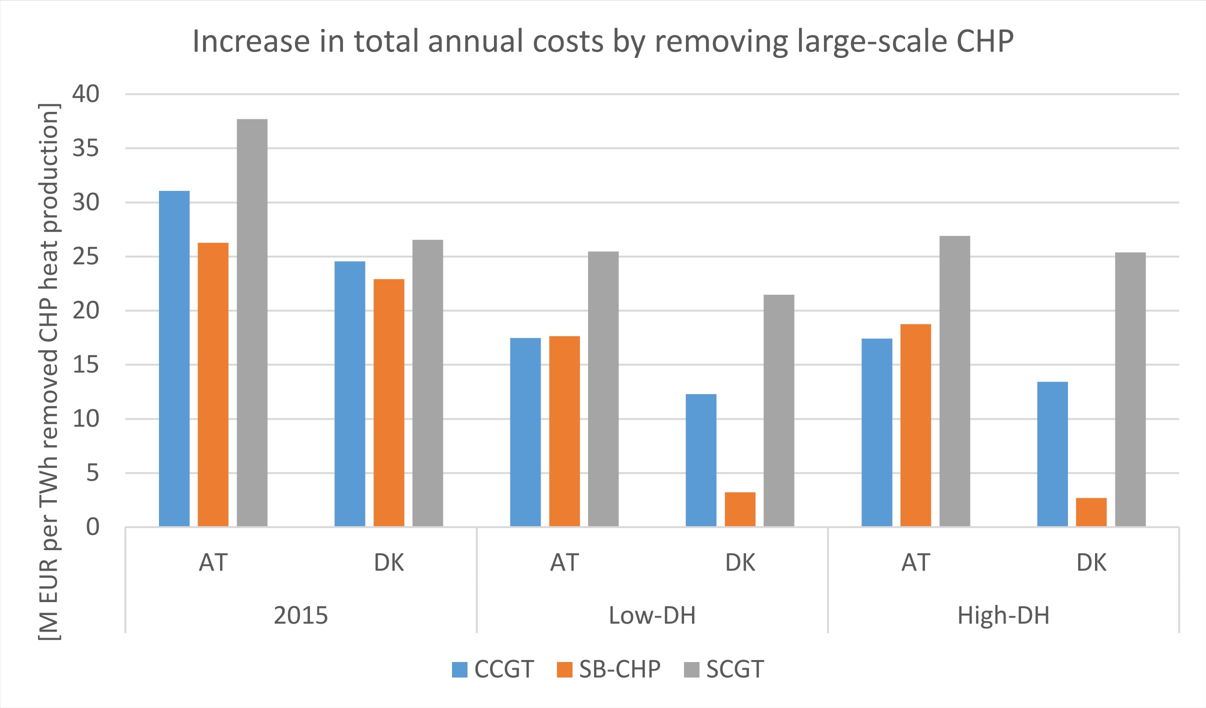

Figure 26: Increase in total annual costs of the entire energy system without large-scale CHP as compared with Figure 21. The increase is expressed per TWh decrease in CHP heat production.

As seen in Figure 26 replacing the large-scale CHP units with power plants increases the energy system cost of all the energy system scenarios. The increase is lowest in the future Danish low-DH scenarios, where the heat production from CHP also is the lowest, and thereby it being easier to replace the DH production from CHP plants with available capacity from low-cost DH production facilities, such as HPs. Generally, the CCGT and SB-CHP technologies have the lowest increase in costs. For the CCGT is due to its higher electric efficiency in power plant configuration compared to SCGT, and for SB-CHP it is due to it producing a larger amount of heat, which in turn affects the cost per TWh.

EXCESS HEAT FROM ELECTROFUEL PRODUCTION

In this section the energy system effects of utilising the excess heat from electrofuel production for DH is analysed. As there is no electrofuel production in the 2015 scenarios, these are not included in the work presented here.

Figure 27 shows the increase in marginal RES production technology for 0% and 50% excess heat utilisation compared to 100% utilisation. The change in marginal RES production is based on the method for changing capacity.

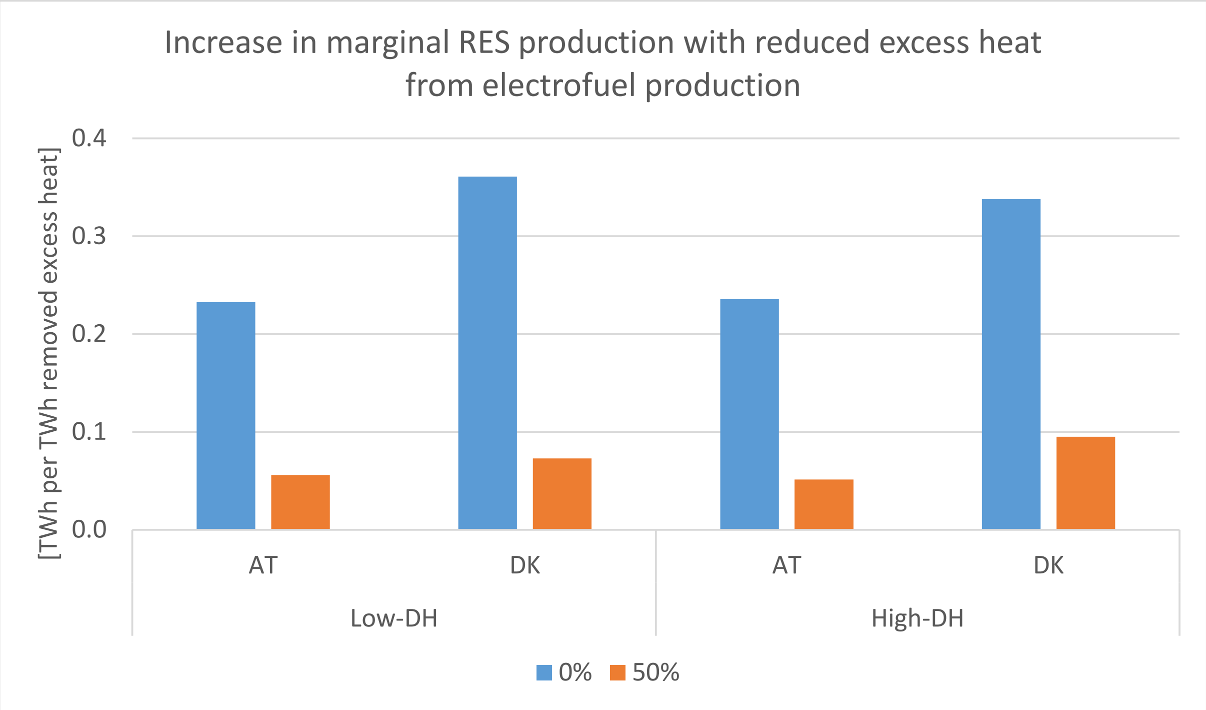

Figure 27: Increase in marginal RES production when reducing the amount of excess heat from electrofuel production to 50% and 0% of potential in scenario. The increase is expressed per TWh excess heat removed.

As shown in Figure 27 as the amount of excess heat utilised is reduced the need for marginal RES production is increased, as the need for other heat sources is increased. The effect per TWh removed excess heat is, however, significantly larger when no excess heat is utilised compared to 50% utilisation. The reason is that the first excess heat removed can more easily be replaced with other efficient DH sources, when the capacity of the other DH production units remains unchanged, but as the amount of excess heat is reduced further, then more inefficient sources are utilised, which increases the need for more marginal RES production for e.g. direct electrification technologies or production of gaseous electrofuels. This can be seen on Figure 28 which shows what technologies are used as replacement DH technologies in percentage of the excess heat removed. Balance is change in amount of DH that could not be utilised or stored and thereby is wasted. As shown in all cases reducing the amount of excess heat utilised also reduce the amount of wasted heat, which is excess heat delivered in the summer months where the DH demand is relatively low.

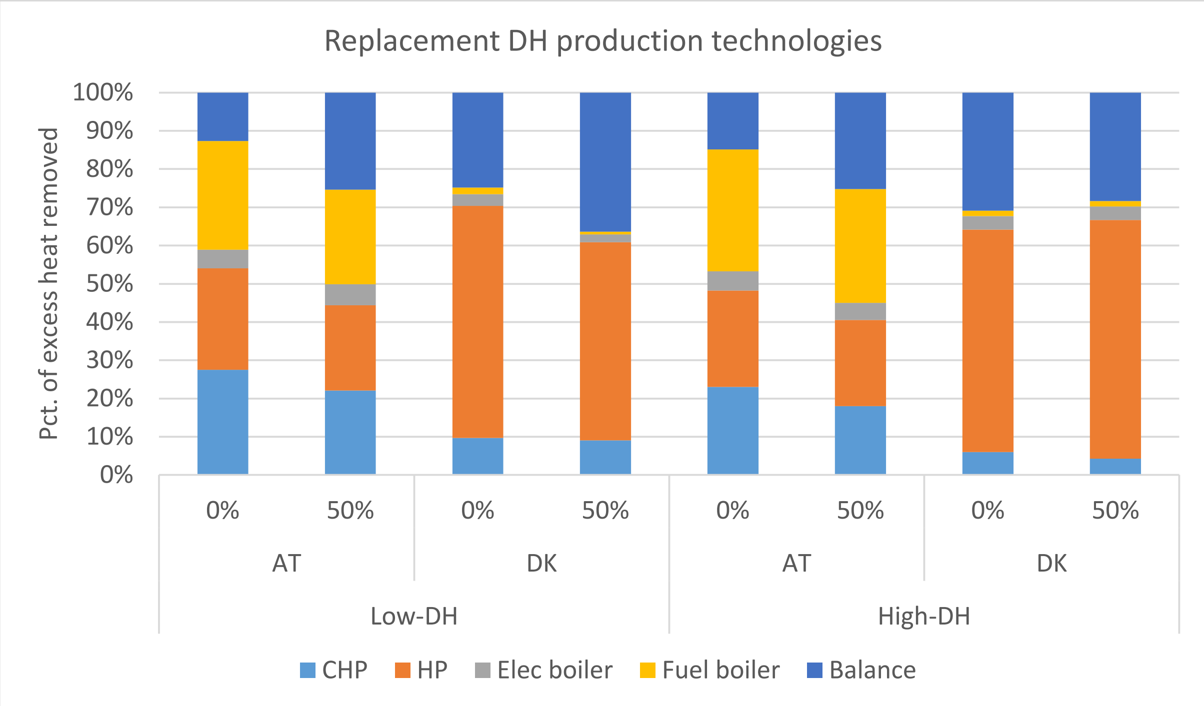

Figure 28: DH production technologies that are used as replacements for reduced utilisation of excess heat

As shown in Figure 28 in all the scenarios utilising less excess heat from the electrofuel production result in lower non-useable heat to be produced in the summer half-year, especially in the DK scenarios that have a larger amount of excess heat from different sources and geothermal heat. The remaining DH replacement is mostly produced HPs in the DK scenarios and in the AT scenarios a combination of CHP, HPs and fuel boilers.

Figure 29 shows the increase in primary energy supply for the entire energy system for 0% and 50% excess heat utilisation compared to 100% utilisation.

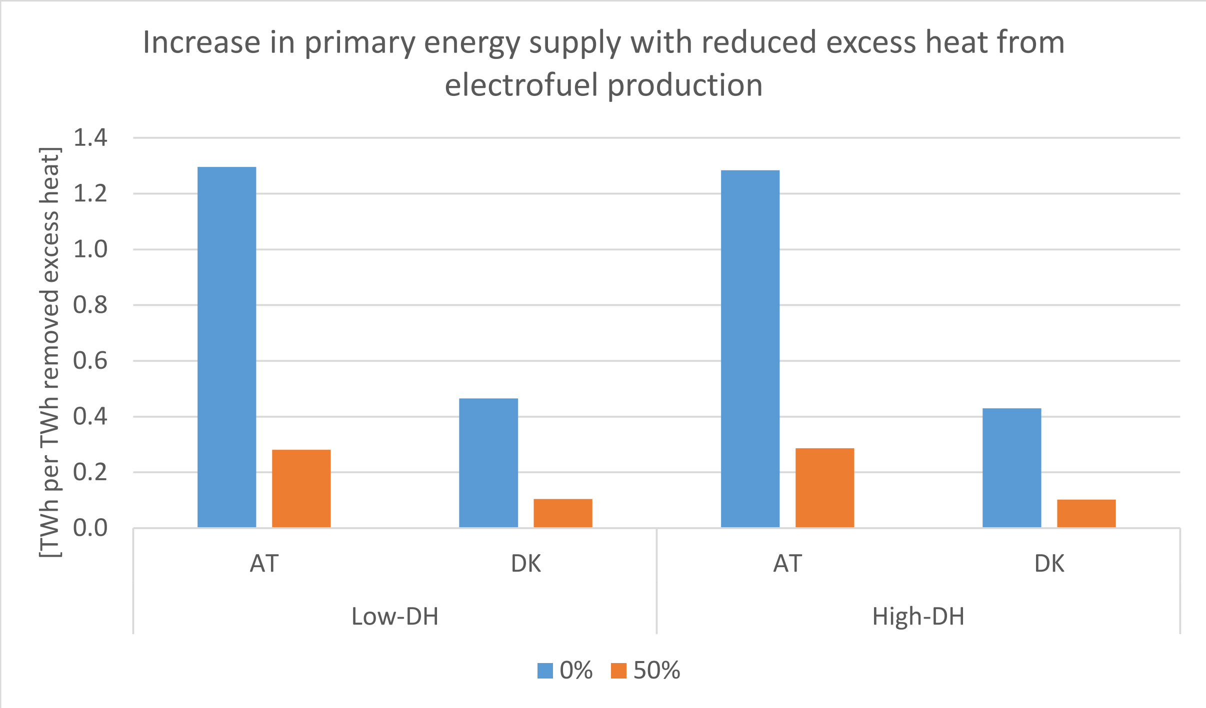

Figure 29: Increase in primary energy supply of the entire energy system when reducing the amount of excess heat from electrofuel production to 50% and 0% of potential in scenario. The increase is expressed per TWh excess heat removed.

Figure 29 shows that as the utilisation of excess heat from electrofuels are reduced, then the need for primary energy supply is increased. The reason is the same as the need for extra marginal RES production shown in Figure 27, that other DH production units need to cover this energy demand instead and as more have to be produced by other units the more and more inefficient units are needed, as shown in Figure 28. The effect is here larger for AT as the HP capacity in DH is relative less in the AT scenarios compared with the DK scenarios, meaning that HPs to a larger extend are used as replacement technology in the DK scenarios than in the AT scenarios.

Figure 30 shows the increase in biomass consumption for the entire energy system for 0% and 50% excess heat utilisation compared to 100% utilisation.

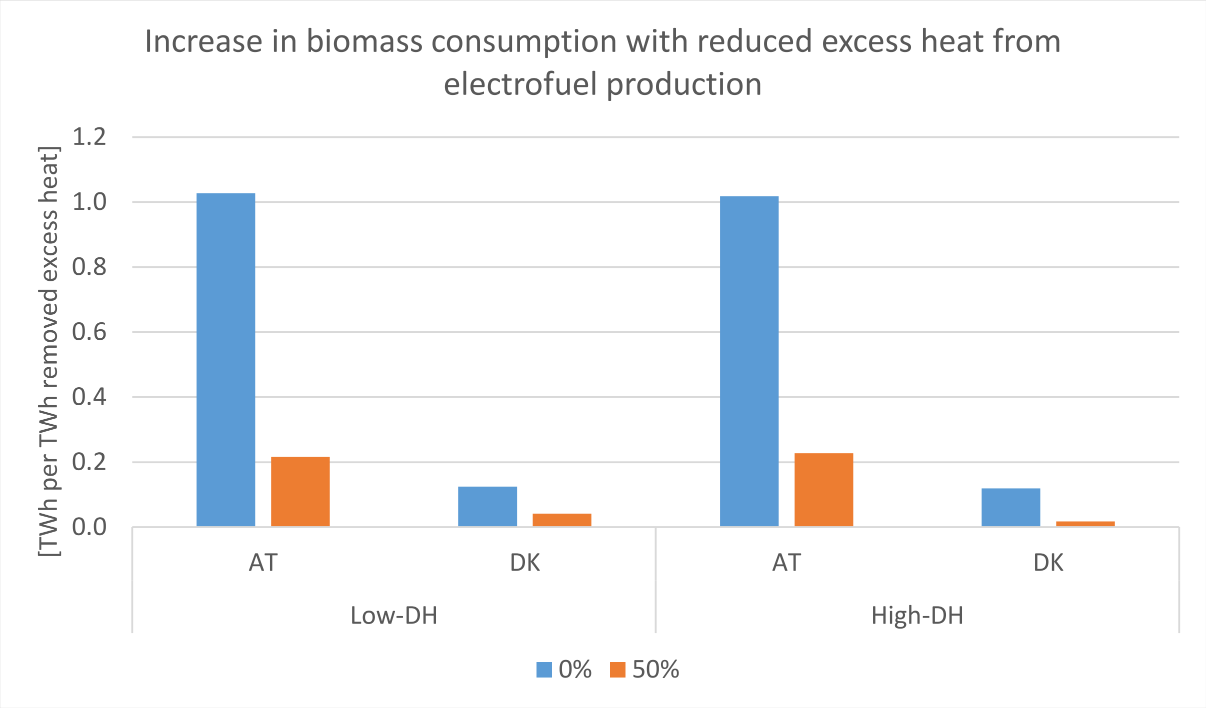

Figure 30: Increase in biomass consumption of the entire energy system when reducing the amount of excess heat from electrofuel production to 50% and 0% of potential in scenario. The increase is expressed per TWh excess heat removed.

As shown in Figure 30 the biomass consumption in the AT scenarios is more affected than the DK scenarios. Again, the difference is due to the difference in available DH production replacement technology. For the AT scenarios the same tendency as shown with primary energy supply is also seen here, meaning that the first 50% reduction in utilised excess heat has a lower effect per TWh removed excess heat than the last 50%.

Figure 31 shows the increase in total annual cost for the entire energy system for 0% and 50% excess heat utilisation compared to 100% utilisation.

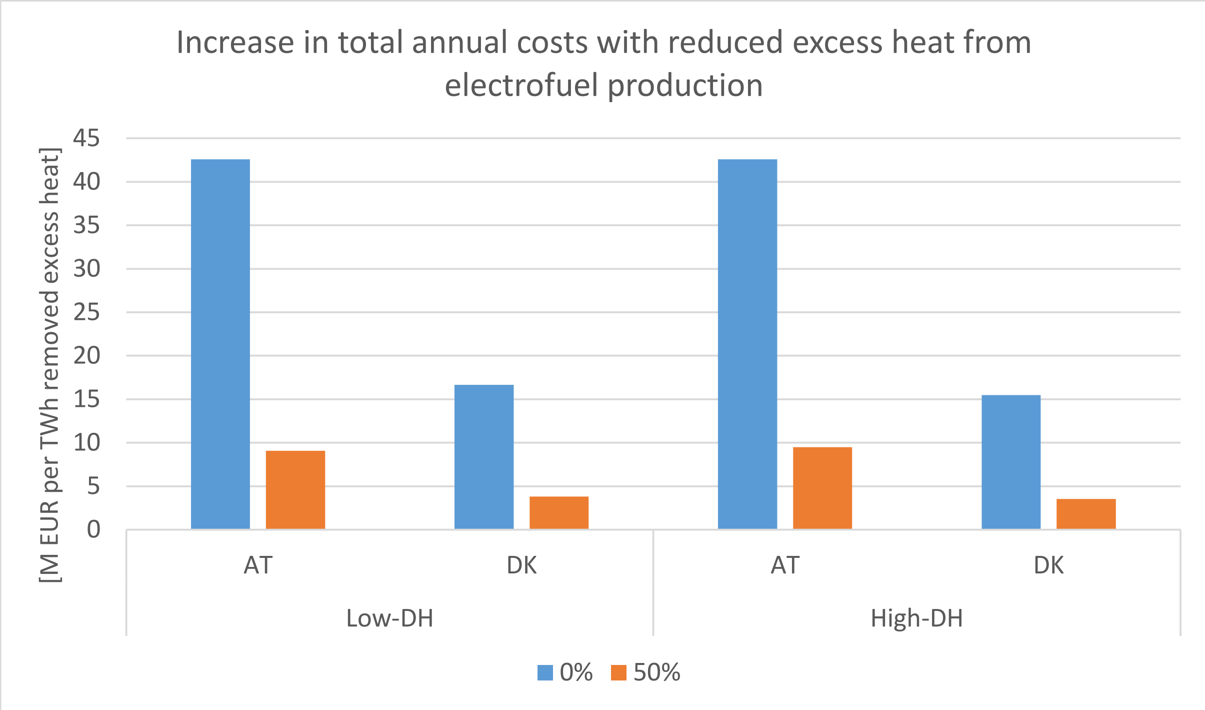

Figure 31: Increase in total annual cost of the entire energy system when reducing the amount of excess heat from electrofuel production to 50% and 0% of potential in scenario. The increase is expressed per TWh excess heat removed.

As shown in Figure 31 a similar effect to what was shown for the other metrics can be seen for the total annual cost, being that the first 50% removed has a significant lower effect than the last 50%. Again, the effects are more significant for the AT scenarios than the DK scenarios, which is mainly due to the differences in the replacement technologies for the DH production as discussed.

TYPE OF ELECTROLYSIS

In this section the energy system effects of different types of electrolysis are investigated. Here both the biomass gasification method as well as the CO_2 methanation method are used for the gas balancing.

Figure 32 shows the increase in marginal RES production technology for the three different electrolysis technologies with 0%, 50% and 100% excess heat utilisation for DH. The difference in marginal RES production is based on the method for changing capacity. The method for gas balance is here the production via CO_2 methanation.

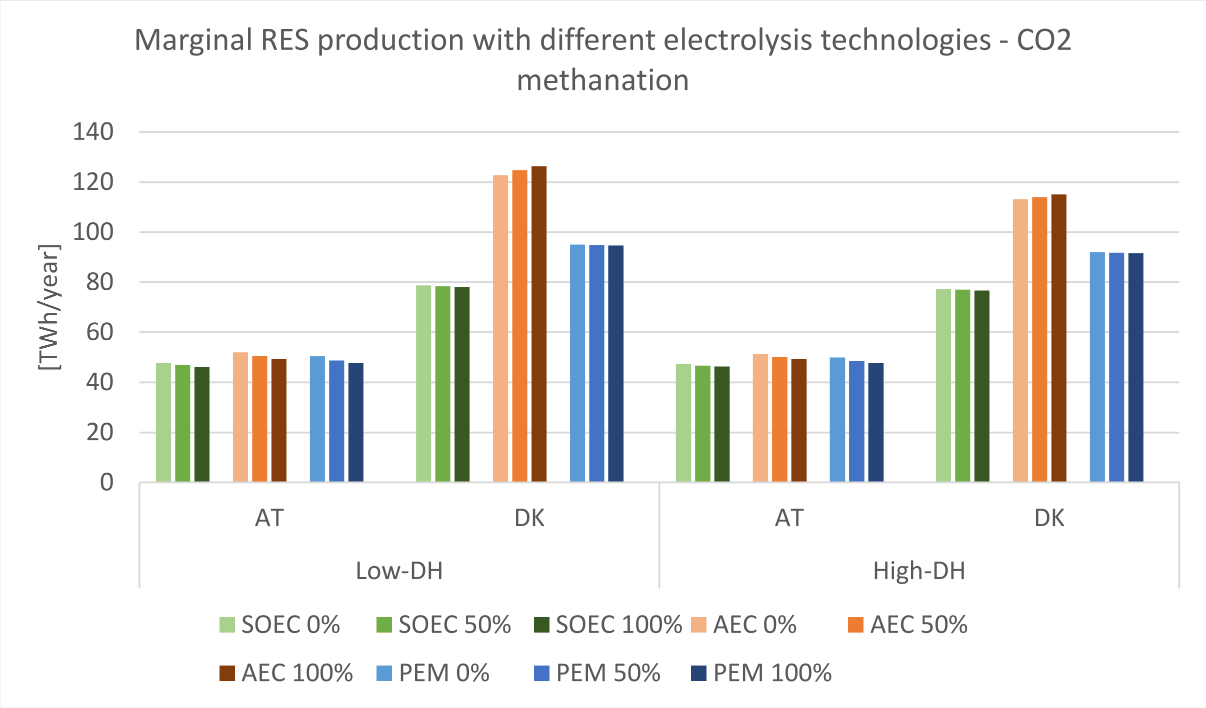

Figure 32: Marginal RES production with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via CO_2 methanation.

As shown in Figure 32 the effects of the lower electric efficiency of AEC and PEM makes these require more marginal RES production installed in both the AT and DK energy scenarios compared with the SOEC. In the DK scenarios the AEC requires the largest amount of marginal RES production due to having the lowest electric efficiency. Generally, increasing the utilisation of excess heat for DH results in reduced need for marginal RES production, though utilising AEC in the Danish energy system shows the opposite tendency. The reason for this is the low electric efficiency of AEC, which results in increased need for gas for thermal plant production in periods with relatively low amounts of wind power, and as amounts of utilised excess heat increased the potential to utilise CHP is reduced, meaning that a larger amount of the electricity is produced via power plants. As such, this increase is related to the method for balancing the yearly exchange of gas in the system, which here is via CO_2 methanation. The results for the AT scenarios have some significant differences, as here there are little effect on the marginal RES production depending on the type of electrolyser, though here the SOEC also show the lowest need for marginal RES production, followed by PEM and then lastly AEC. This is both related to more dispatchable RES energy sources in the AT that allow for better utilisation of increased amounts of variable RES, but also due to the thermal plants being fuel mostly by biomass, meaning that as the need for operation of these increases, then the need for gaseous electrofuel is not increased to the same extend as in the Danish scenarios, which turn means that effect should more be seen in relation to both the marginal RES production as well as the biomass consumption.

To show the effect of the chosen method for gas balancing the system, Figure 33 shows the same analyses as Figure 32, though here the gas exchange is balanced with biomass gasification.

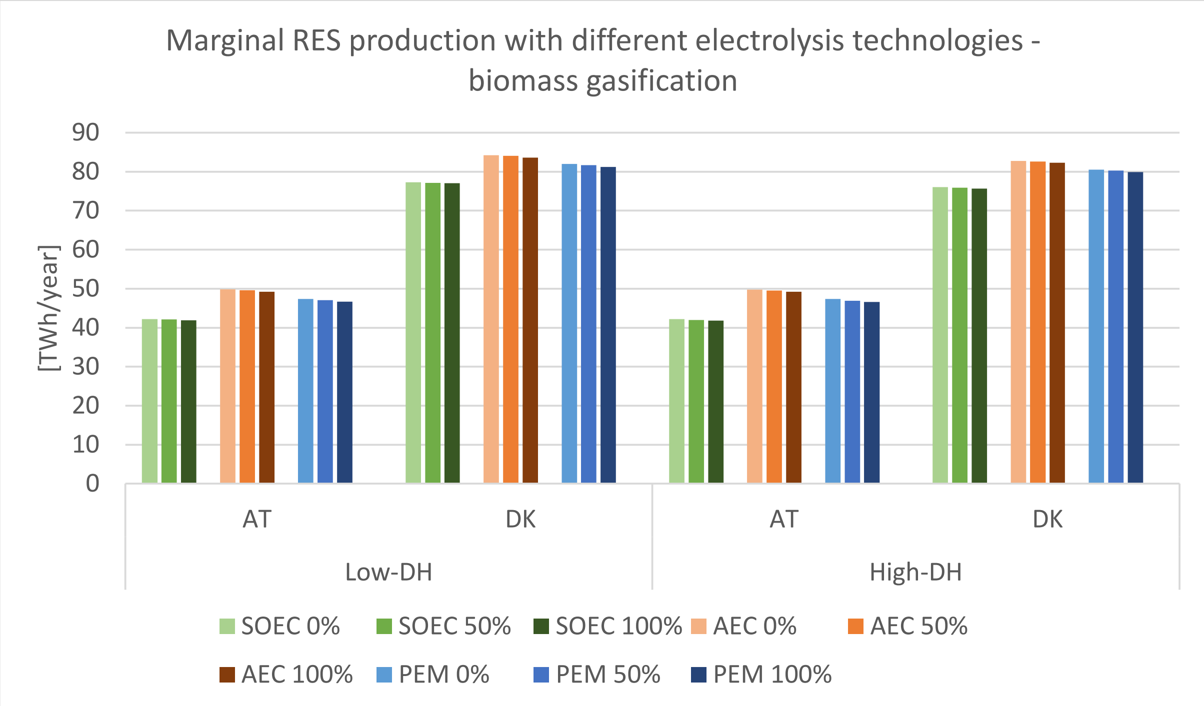

Figure 33: Marginal RES production with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via biomass gasification.

Comparing Figure 32 to Figure 33, when using biomass gasification instead of CO_2 methanation the marginal RES production is lower in all cases, though SOEC will have similar amounts. It can also be seen that even though the difference between the different technologies is much lower, the SOEC still have the lowest need for marginal RES production followed by PEM and AEC. There is also a small decrease in the amount of marginal RES production with increased utilisation of excess heat from AEC as well, which was not the case with the CO_2 methanation method.

Figure 34 shows the biomass consumption for the entire energy system for the three different electrolysis technologies with 0%, 50% and 100% excess heat utilisation for DH, with CO_2 methanation as the gas balancing unit.

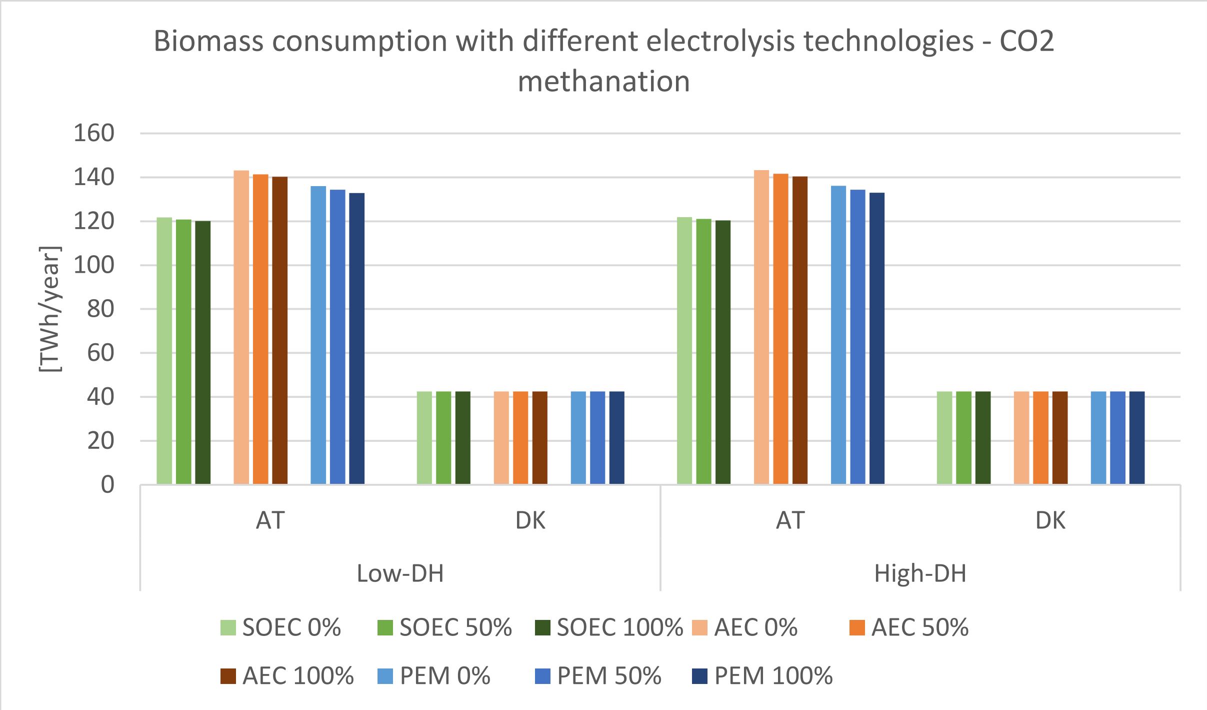

Figure 34: Biomass consumption of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via CO_2 methanation.

As shown in Figure 34 the DK scenarios biomass consumption is the same in all scenarios, as the fuel consuming units for electricity and DH production utilise gas which in these results are balanced via CO_2 methanation. For the AT scenarios the biomass consumption is highest with AEC electrolysers followed by PEM and SOEC. This is related to the electric efficiency of the technologies, with the AEC having the lowest electric efficiency followed by PEM and SOEC. Increased utilisation of excess heat also reduces the need for biomass, though the effect is larger with AEC and PEM which also is technologies with the largest potential for excess heat.

Figure 35 shows the same analyses as Figure 34, though here the gas exchange is balanced with biomass gasification.

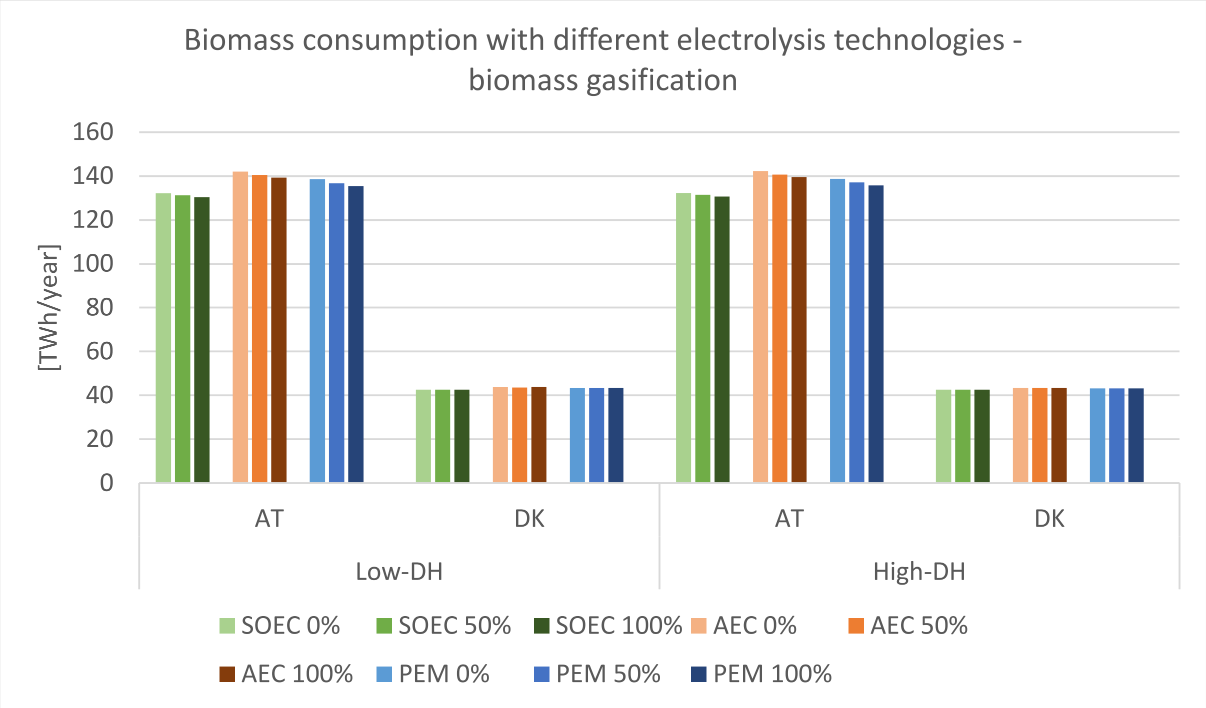

Figure 35: Biomass consumption of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via biomass gasification.

Comparing Figure 34 and Figure 35, using the biomass gasification increases the amount of biomass consumption in the DK scenarios, though only with 0.1-0.2 TWh with SOEC, 1-1.3 TWh with AEC and 0.7-1 TWh with PEM. For the AT scenarios the biomass consumption increases with around 10 TWh with SOEC and 2.3-2.7 TWh with PEM, but it drops with 0.8-1.3 TWh with AEC, which is due to a change in operation of CHP and power plants, where the CHP is 50% gas and 50% biomass the power plants are 100% biomass, and as less excess heat comes from electrolysis with biomass gasification compared with CO_2 methanation, then the CHP is operated more. This, of course, is also related to the assumption that no excess heat from biomass gasification is utilised, as including this would reduce the potential to use CHP plants instead of power plants.

Figure 36 shows the primary energy supply for the entire energy system for the three different electrolysis technologies with 0%, 50% and 100% excess heat utilisation for DH, with CO_2 methanation as the gas balancing unit.

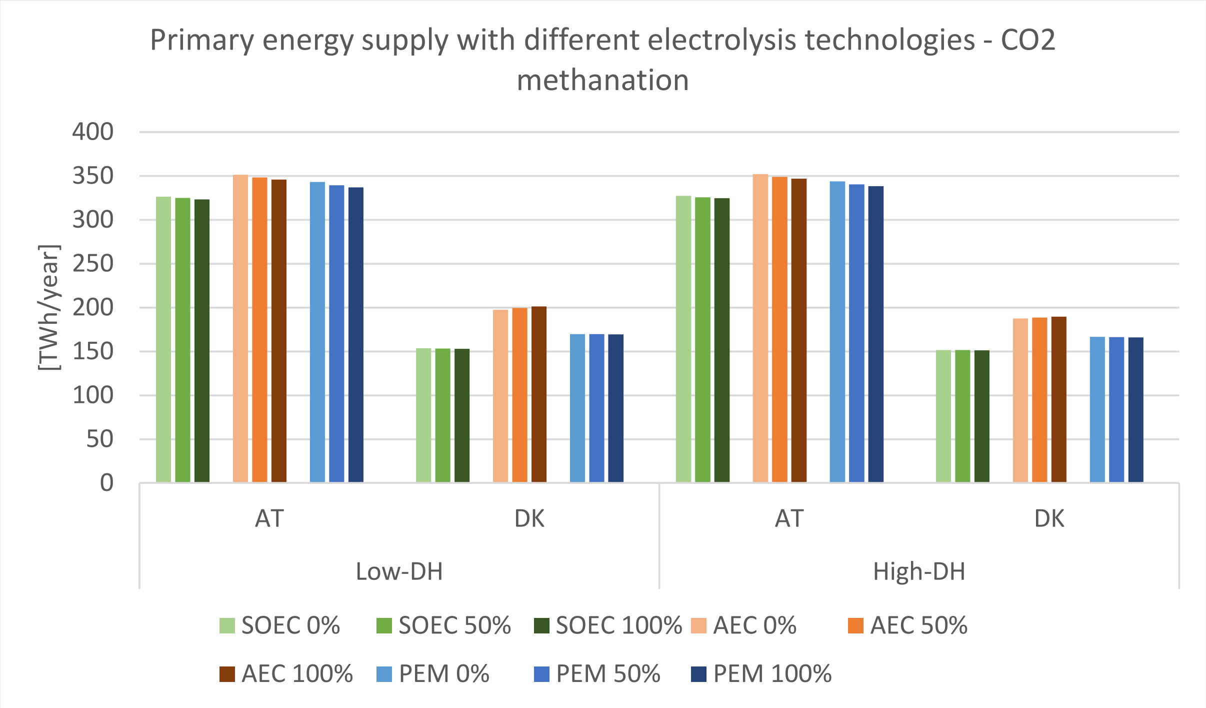

Figure 36: Primary energy supply of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via CO_2 methanation.

As shown in Figure 36 the sum of the tendencies shown in Figure 32 and Figure 34 can be seen for the primary energy supply. Meaning that the AT increases mainly are grounded in the increases in biomass consumption, and the increases in the DK scenarios are only due to increases in the marginal RES production unit. The effect of utilising the excess heat has a larger effect on the primary energy supply for the AT scenarios than for the DK scenarios.

Figure 37 shows the same analyses as Figure 36, though here the gas exchange is balanced with biomass gasification.

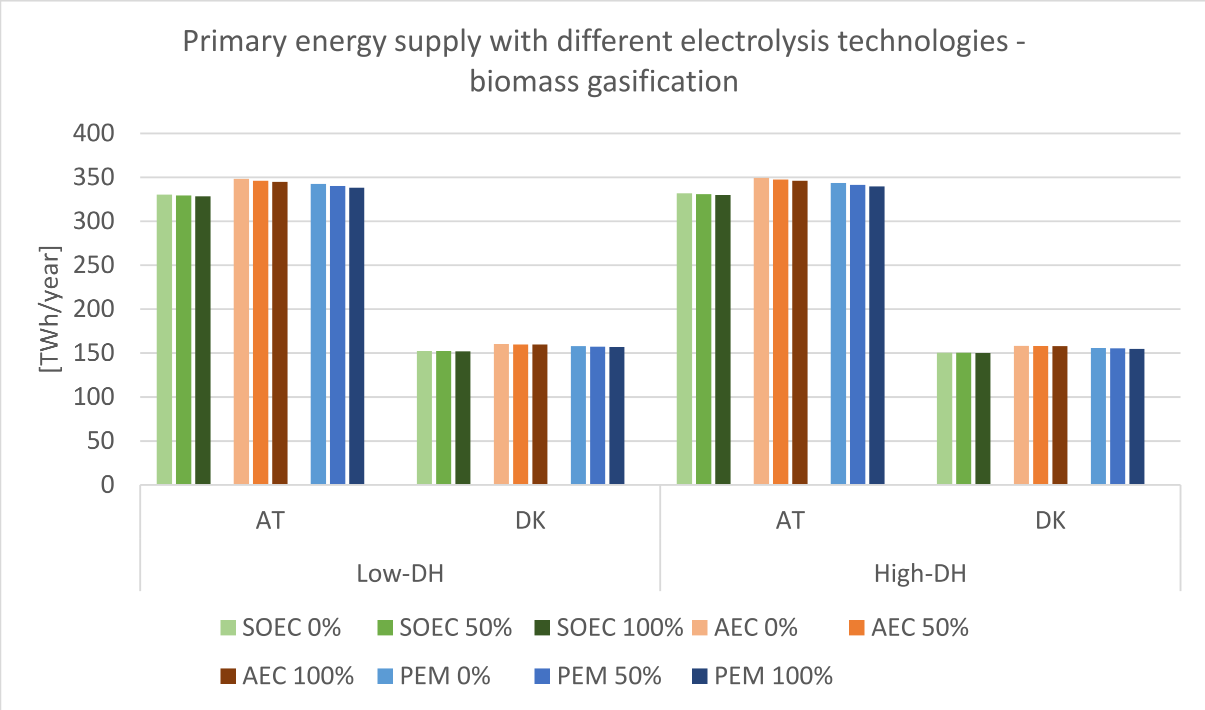

Figure 37: Primary energy supply of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via biomass gasification.

Comparing Figure 37 with Figure 36 it can be seen that for the DK scenarios the primary energy supply for SOEC is mostly unaffected by the choice of biomass gasification and CO_2 methanation, whereas both AEC and PEM sees lower primary energy supply with biomass gasification. For the AT scenarios, the primary energy supply for the SOEC is a 4-5 TWh higher which is directly related to a higher biomass consumption, whereas the primary energy supply for AEC decreases a bit and the PEM is mostly unchanged compared with CO_2 methanation as gas balancing unit.

Figure 38 shows the total annual cost for the entire energy system for the three different electrolysis technologies with 0%, 50% and 100% excess heat utilisation for DH.

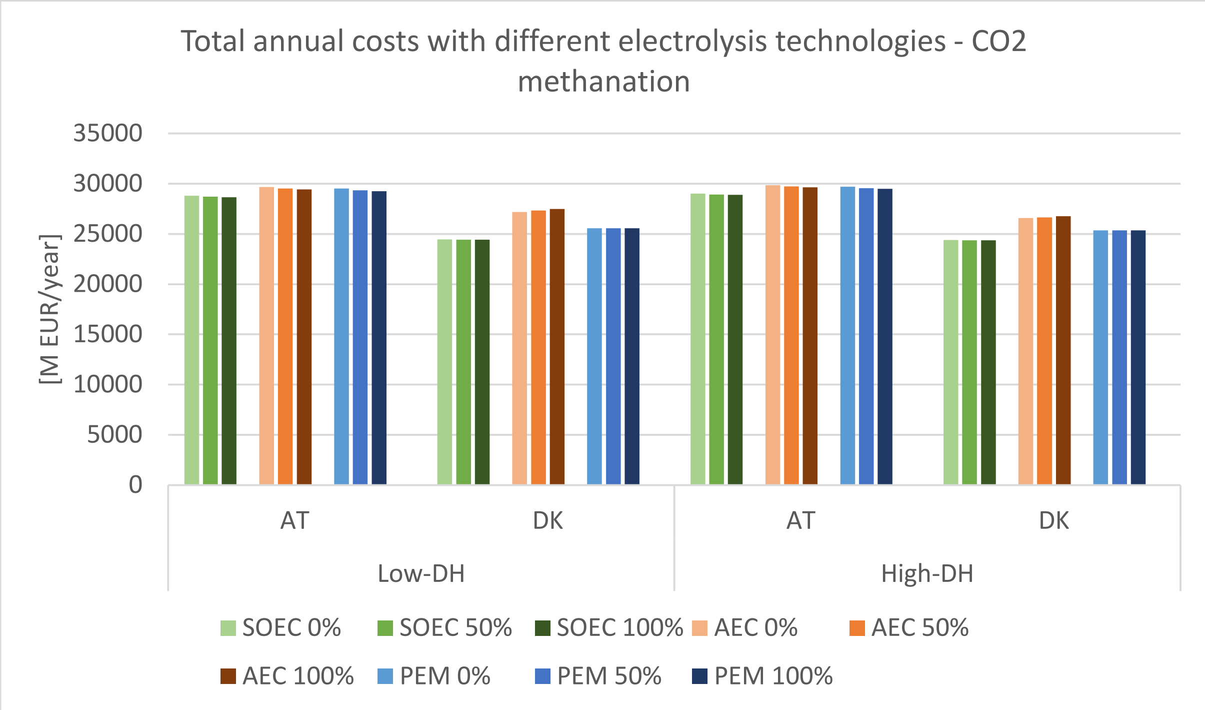

Figure 38: Total annual cost of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via CO_2 methanation.

Figure 38 shows that SOEC in all cases provides the lowest total energy system costs, followed by PEM and lastly AEC. The effect on the energy system costs of utilising excess heat is largest in the AT scenarios, where the excess heat especially replaces heat from CHP, HPs and fuel boilers. In the DK scenarios the excess heat mostly replaces HPs and result in increasing non-usable heat in the summer period. This difference means that the value of the excess heat is lower in the DK scenario than in the AT scenario.

Figure 39 shows the same analyses as Figure 38, though here the gas exchange is balanced with biomass gasification.

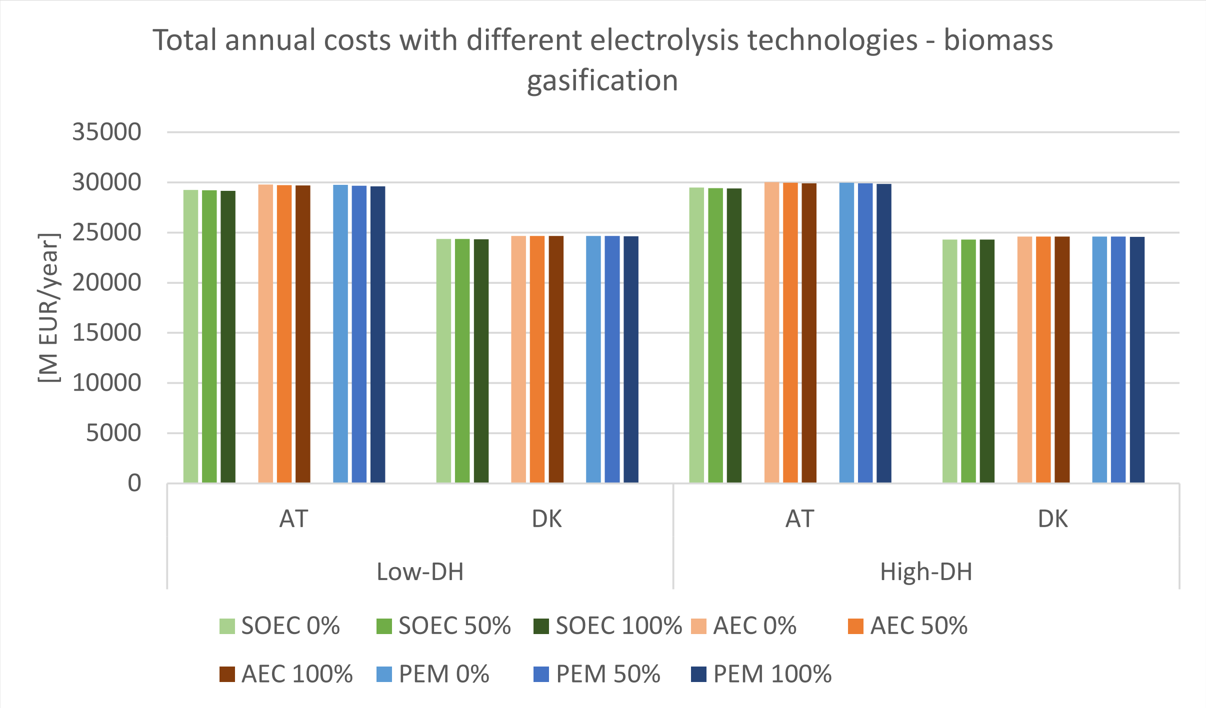

Figure 39: Total annual cost of the entire energy system with different electrolysis technologies and different levels of utilisation of excess heat for DH (0%, 50% and 100%). Gas balance via biomass gasification.

Comparing Figure 39 with Figure 38 it is clear that the effect of the method for gas balancing with gaseous electrofuels via CO_2 methanation have a significant effect on the cost difference between the types of electrolysers in the DK scenarios, where the cost difference from SOEC to AEC is about 2,300 M EUR/year with CO_2 methanation as the gas balance, while if biomass gasification would be used instead then the cost increase would only be 300 M EUR/year. However, across the different scenarios SOEC shows to be the electrolysis technology that provides the lowest energy system costs, followed by PEM and lastly AEC.

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