The future role of Thermal Biomass Power in renewable energy systems

- study of Germany

Skærbæk CHP plant, Denmark. Photo: Ørsted

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The future role of Thermal Biomass Power in renewable energy systems – a study of Germany

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Executive Summary

The global energy supply system is in a transition from a centralized system dominated by dispatchable fossil-based sources to a system that is based on renewable energy sources. In countries where wind and solar are expected to play a dominant role in the energy transition, the integration of these energy sources in the power system places pressure on the grid operation as their supply is variable and non-dispatchable. This raises the challenge of balancing demand and supply in the power grid, especially in hours with low generation from wind and solar and given the fact that often these sources are generating when demand is low.

Bioenergy, being a dispatchable form of renewable generation, has the potential to play a key role as a stabilising element in a future green power system dominated by variable renewable energy. Following the interest expressed in the framework of the IEA Bioenergy, Task 32 has decided to further explore the role of thermal biomass power plants in the future, using a system approach.

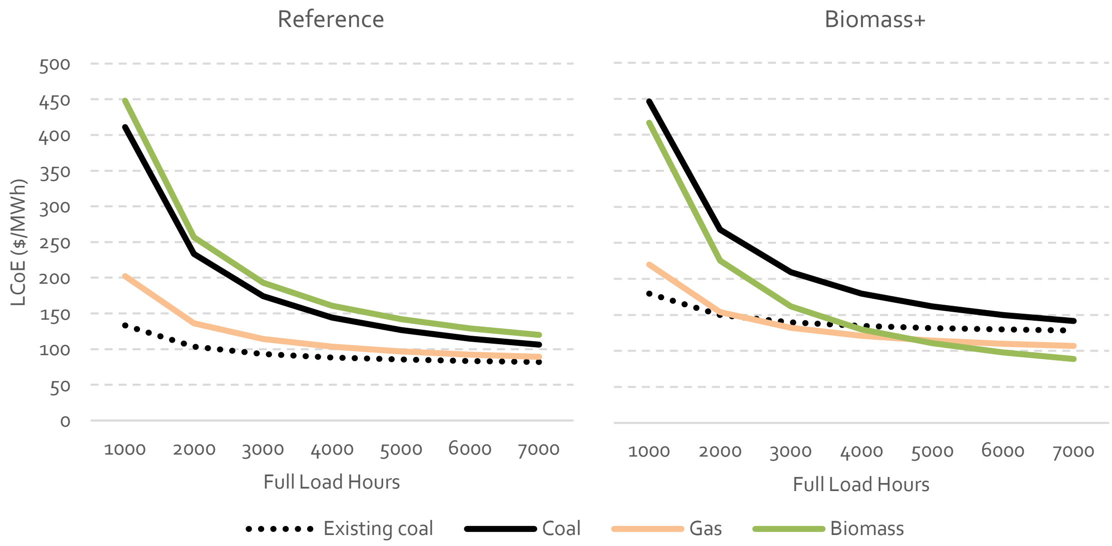
In this analysis, development of the European power system is projected highlighting a thermal-dominated area, exemplified by Germany. The role of biomass technologies towards 2040 is analysed in two scenarios, *Reference* and *Biomass+,* utilizing the Balmorel model, a fundamental mathematical model of power and heat systems reproducing the day-ahead market dispatch and future development of the generation fleet.

The *Reference scenario* is characterized by current preconditions and assumptions that represent a consolidated estimate of future demand, fuel prices, CO_2 costs, investment costs, etc. It reflects a situation where the recent suggestion to decommission all German coal power by 2038 is not implemented. The scenario shows very limited biomass-based electricity generation capacities and generation in 2040 in Germany and Europe more broadly while coal still plays a significant role. Not only biomass, but all conventional technologies in the power sector will be challenged by increasing competitiveness of wind and solar generation.

The model results underline the need for "firm and dispatchable" power in the electricity system. Gas, coal, biomass and to a certain extent nuclear technology fall in this category. However, due to increased utilisation of hydropower, increased flexibility in demand and increased cross-border, market and sector integration, the demand for firm and dispatchable power technologies will decrease substantially. The deployment of potential new storage technologies will contribute to challenging the business case of conventional power plants.

In the *Biomass+ scenario*, a more favourable framework for the deployment of biomass has been simulated by assuming two main drivers compared to the reference: a doubled CO_2 price by 2040 and a biomass feedstock price halved from 2020 onward. The calculations for 2040 show that under these enabling conditions, substantial investments in biomass-based generation capacity take place and biomass power plants run for high numbers of annual operational hours, acting as baseload. Concurrently, biomass has also the potential to contribute with large share of district heating production, with heat revenues being an important driver for utilizing biomass CHP technologies. On the other hand, system flexibility services would be primarily delivered by more responsive hydropower, pumped and other electricity storages, and gas-fired power units.

Biomass is in direct competition with coal and natural gas, the main sources displaced in the Biomass+ scenario. CAPEX and OPEX ratios between these technologies are key in determining how they are dispatched, and consequently their overall economic competitiveness. Higher CO_2 price and lower biomass prices (or corresponding incentives) will decrease the levelized cost of electricity from biomass, especially at high utilization rates, making it able to compete even with existing coal power plants, which might be driven to decommissioning, co-firing or full conversion as is shown in the figure below. In this way, the scenario is an example how a decision following the recent suggestion to decommission all coal power plants by 2038 could be implemented.



It can be concluded that the existing and estimated future market conditions alone will not be able to drive substantial amounts of thermal biomass power into the German (and European at large) energy system up to 2040 due to competition with existing fossil fuel plants and cheap wind and solar investments. Special framework conditions and/or low feedstock prices are needed to see a large role for biomass in a future thermal-dominated power system like in Germany and more broadly in Europe.

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2 Background and introduction

The global energy supply system is currently in transition from a centralized system dominated by dispatchable fossil-based sources to a system that is based on renewable but variable energy sources. Optimising the stability and cost-effectiveness of such a future system requires seamless integration and control of various energy inputs. The role of energy supply management is therefore expected to increase in the future to ensure that customers will continue to receive the required amount of energy at the required time.

In countries where wind and solar are expected to play a dominant role in the energy transition, integration of these variable energy sources with the power grid places pressure to the reliability of grid operation as the supply of the power from renewables is variable and non-dispatchable. This has led to discussions on how to balance the grid. Furthermore, often the renewable electricity from wind or solar is provided in times when demand is low and the electricity must be stored, requiring expensive storage systems or even curtailment of energy, potentially leading to economical inefficiencies. Bioenergy can be an option to relieve the pressure from system level management of the grid by making the grid more stable. In this respect, bioenergy has the potential to play a key role as a stabilising element in a future power system dominated by renewable energy.

In the scope of Task 41 Project 6 "Bioenergy in Balancing the Grid & Providing Storage Options", IEA Bioenergy has aimed to identify and develop new opportunities in the area of grid management and storage where bioenergy can play a strategic role. Task 41 Project 6 has been reported in 2017, please see [1]. As IEA Bioenergy recognised the relevance of this aspect, a new IEA Bioenergy task has been launched as of 2019 to understand in greater depth how bioenergy could play a complimentary role to other renewable energy sources in the future energy supply.

While mainly focusing on integration of biogas, district heating and electricity distribution networks, the Task 41 project states that the energy market will transform from an energy optimized system to a capacity optimized system when the share of intermittent or uncontrollable electricity becomes large enough. The project concludes that bioenergy could contribute more than it already does to balancing future grids.

In 2017, Task 32 Biomass Combustion and Co-firing assisted the IEA in developing the Technology Roadmap - Delivering Sustainable Bioenergy [2]. The contribution suggests that in the short term, new large biomass-based power units will have to be CHP units installed in areas with a heat demand.

In the medium term, up to 2035, options to install new combustion capacity will be limited and new units will need to be cheap and more flexible while retrofit of potentially existing plants from fossil fuels to biomass combustion is expected to require some sort of fuel pre-treatment technology.

When looking at the longer term - after 2035 - nuclear energy is being phased out and residues from the emerging biorefineries may require biomass-based CHP to partially fill in the resulting demand for dispatchable capacity. Emerging Bioenergy Carbon Capture and Storage technologies may depend on biomass combustion as a cost-effective means to reduce atmospheric CO_2 concentrations.

In a survey that IEA Bioenergy carried out in 2017 to identify member countries preferences regarding future action areas, there was a clear call for a system approach to describe the future role of bioenergy in the future power and heat sector.

On top of this ongoing work with technology development as well as biomass flexibility and system balancing efforts in the IEA Bioenergy and the mentioned survey, Task 32 Biomass Combustion and Co-firing has decided to explore further the role of thermal biomass power plants, combined heat and power plants, in future energy systems, more and more dominated by variable renewable energy.

The starting point has been the identification of various energy system archetypes, i.e. system defined by a different combination of natural resources, generation fleet and typical generation patterns. Examples of energy system archetypes could be the following:

- A thermal-dominated system (like in Central Europe)
- An island system (like an Indonesian island)
- A hydro-dominated system (like Scandinavia, Canada)
- A nuclear based system (like France),

Other dimensions differentiating the various systems could be identified, for example district heating penetration, demand seasonality, level of market integration (interconnection). It is evident that the role biomass can play in the system, as well as the design and flexibility requirements of the power plant, are strongly affected by the inner characteristics of the archetype.

In the framework of this analysis, the focus has been placed on a thermal-dominated system and Central Europe, more specifically Germany, has been chosen as a representative for the archetype. By utilizing the Balmorel model, a fundamental model of power and heat systems reproducing the market dispatch and development of generation fleet in the future, the study will try to assess the role of biomass in the future for the archetype selected. Future studies will potentially explore the viability and role of biomass in other archetypes.

2.1 THERMAL SYSTEM ARCHETYPE, THE CASE OF GERMANY

The German power system has been chosen as a thermal-dominated archetype based on its main characteristics. In 2018, the vast majority of the annual power demand has been covered by thermal plants, namely coal (38%), Nuclear (13%), Bioenergy (8%) and Gas (8%) [3].

In recent years and thanks to a steady public support in terms of direct subsidies, the amount of renewable energy in the system, especially wind and solar, has been surging (Figure 1). This effort towards higher deployment of renewable energy are part of a planned transition to low carbon called Energiwende (German for energy transition).

As part of this plan, especially after the Fukushima accident in Japan, Germany also decided to phase-out their nuclear generation by 2022. As of 2019, already half of the nuclear reactors has been decommissioned [4]. More recently, in January 2019, a government-appointed commission in Germany announced a plan to decommission all coal power plants by 2038 [5], following similar announcement by European governments.

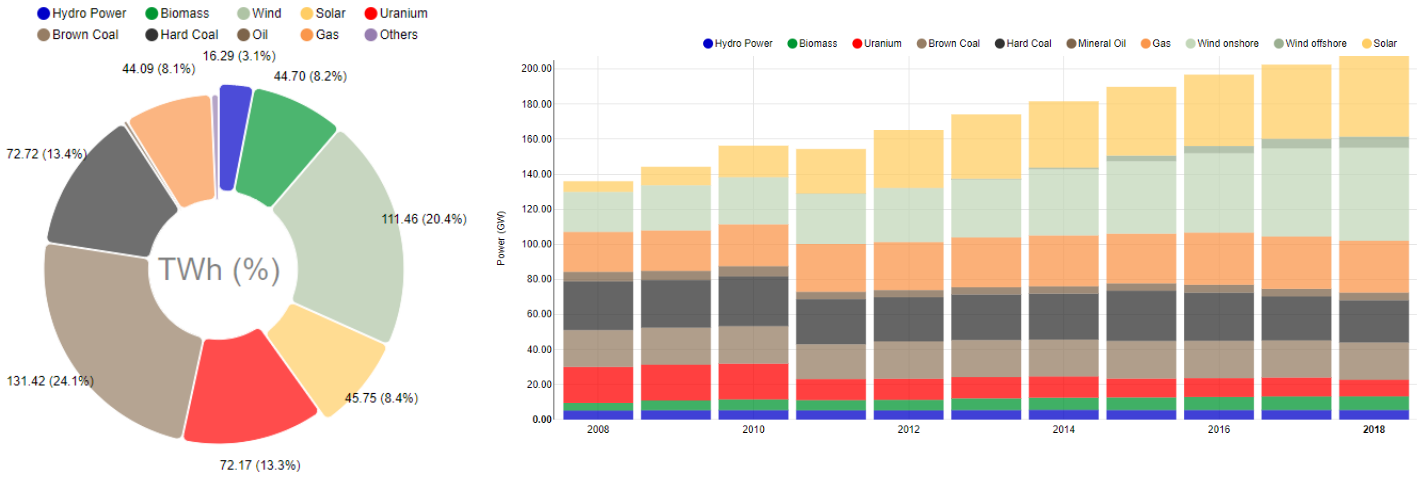

Figure 2.1 *Annual generation by source in 2019 (left) and evolution of installed capacity (right) in the German power system. Source: [1]*

As for the district heating, around 1400 systems of various sizes exists in the country, for a total connected load of 57 GW_{th}. The largest systems are those supplying the main cities such as Berlin, Munich, Hamburg, Dusseldorf and others. Around 13% of the electricity producing units are CHP, which also constitutes around 84% of the district heating supply [6].

The German power system is also largely interconnected, given its central position in Europe. Main connections with France, Austria, Switzerland, Belgium, Netherlands, Denmark, Poland, Czech Republic allow Germany to act as a de-facto power hub of central Europe. However, internal bottlenecks mainly between the north and the south limits the amount of power that can be transmitted along that axis.

As a final note, it has to be mentioned that the utilization of biomass for direct combustion in power plants has been largely debated in Germany. The *Energiewende* does not put a lot of focus on biomass toward direct firing in thermal power plants, but rather on concentrating the use of bioenergy in other sectors with less alternatives available, such as industry and transportation. In fact, of the annual 150 MW auctioned for support, already a low number considering the size of the German power sector, only around half have been assigned this year and even lower numbers have been experienced in the previous [7]. This testifies both a moderate ambition toward the sector and low competition in the industry.

3 Methodology, model and main assumptions

This section describes the scenarios analysed with respect to the research question of the study and proceed with an overview of the methodology used and the Balmorel model. Finally, the main assumptions behind the development of the European power system are presented.

3.1 THE EUROPEAN POWER SYSTEM AND ITS DEVELOPMENT

The analysis of the impact of biomass fired generation in Germany is made in the context of a wider European power system that transitions to high shares of renewable energy generation and sees increasing electrification of the heat and transport sectors. These changes are brought about by a combination of national renewable energy policies, a rising carbon price and continued technological development that combine to make renewable generation technologies the least-cost option for new investments in the power market.

The development of the European power system depends on a range of parameters, including the development of fuel prices, the level of ambition for climate targets, technology costs, and regulations. All of these will affect the composition and operation of the power system, and in turn affect biomass deployment. The text box below summarizes the main approach and assumptions in relation to the central parameters which create the framework of the European power system development and serve as a reference development for the study. Additional details on the specific assumptions can be found in Appendix 1.

Table 3.1 Main drivers for power system development and reference assumptions used.

Key factor	**Reference scenario assumptions**
How will fuel prices develop?	Climate policies and technological development will dampen the demand for fossil fuels. Hence, current low forward prices will converge toward the IEA's Sustainable development scenario from World Energy Outlook 2017
What climate targets will the EU and its member states pursue for 2030 and beyond?	The EU will pursue an active climate policy, also beyond 2030. Some Eastern European member states might be less ambitious. The European Commission recently published a 2050 Vision on how to comply with 1.5 degree scenario [8], testifying the intention to decarbonize the energy system
Will renewable energy technologies mainly be supported through subsidies or indirectly by means of a carbon price?	It is generally anticipated that incentives will shift from subsidy to carbon pricing and other market-based measures (payment for ancillary services, capacity, etc.)
How will technological development influence power markets? • *Cheaper solar PV, onshore and offshore wind* • *New storage technologies* • *Flexible electricity demand and smart grids*	Investment cost of renewable energy technologies will decrease to the extent that their production profile becomes the major barrier for further market uptake. An increase in flexible demand will help integrating additional amount of VRES. New storage technologies and smart grid technologies will not have major deployment towards 2030 but can gain increasing importance towards 2050.

3.2 THE BALMOREL MODEL – A SYSTEM APPROACH

In order to analyse the aforementioned development of the European[1] power market, the fundamental market model Balmorel is used. The model is particularly fit for the analysis since it performs optimal dispatch of power plants, by reproducing the mechanism behind the day ahead market, i.e. it finds a supply and demand equilibrium in the combined electricity and district heating sectors by co-optimising both the dispatch of units and investment in new generation capacity under a given set of assumptions and framework conditions.

The development of European power generation capacity, as identified by the model, is the result of a combination of exogenous assumptions, such as existing generation and interconnector capacity, expected capacity expansions and decommissioning, as well as model-optimised investments in power and heat generation as well as transmission capacity, which depend on market conditions and technology costs.

The simulations with the Balmorel model are carried out for a geographic area comprising the Baltic countries, the Nordic countries, Poland, Germany, the Benelux countries, Great Britain, France, Switzerland, Austria, the Czech Republic and Italy. The countries included in the analysis, hereafter the *modelled area*, are highlighted in dark blue in Figure 3.1. While not covering the whole EU-28, the modelled area covers those areas of the power market significant to the analysis of market developments in Germany.

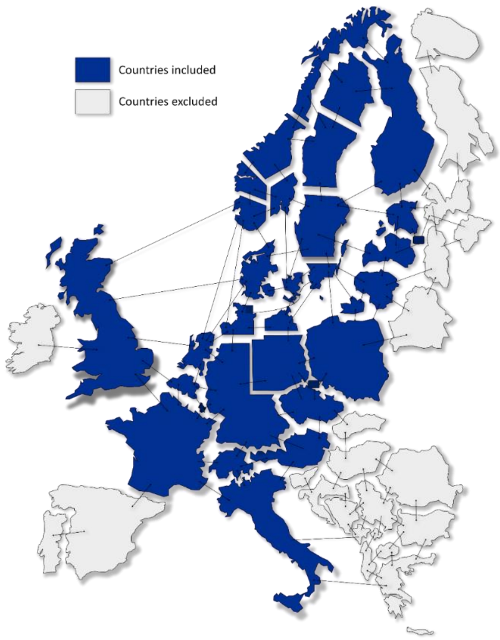

Figure 3.1: Countries included in the power system analysis (modelled area).

Table 3.2 shows an overview of the exogenous assumptions and model optimization for the analysis. A more thorough description of the assumptions and model input can be found in Appendix 1.

[1] Figure 2 shows the countries included in the power system analysis.

Table 3.2 Exogenous assumptions and model optimization for the analysis.

	Exogenous requirements/assumptions	Model optimisations
RE capacities	Minimum requirements reflect minimum national ambitions towards 2030. After 2030, no further increases in minimum requirements.	Model can build capacity above minimum requirement if beneficial based on costs and market conditions.
Nuclear capacity	Best estimate reflecting national policies/decided plans. Unchanged across scenarios.	No model optimisation.
Fossil fuel capacities	Current capacities and already decided decommissioning in the short run. Policies for phase-out of coal power are taken into account by reducing exogenous capacity for the relevant countries.	The model can decommission existing capacities after 2020 if not economically viable on market terms. The model can invest in new capacities if viable on market terms. For all countries except Poland, no new coal power investments are allowed.
Transmission capacities	Expected buildout based on current TYNDP towards 2030.	Model optimisation of general transmission system after 2030.
Power demand	Assumed exogenous trajectory for electricity demand from households, service sector, most industrial demand, heating in buildings (excl. district heating) and transport.	Model-optimised use of power for district heating, industrial electrification and process heat. Model has some flexibility on the hourly demand profile for the different demand types.
Fuel prices	Fossil fuel price levels based on forwards in the short-term converging to IEA' WEO17 "Sustainable development" scenario. Biomass prices based on forwards for short term converging to long-term equilibrium market prices using a biomass price model developed for the Danish Energy Agency.	
CO_2 prices	CO_2 price levels based on forward prices in the short-term converging to ENTSO-E's "EUCO 2030" and "Sustainable transition"	
Power prices		Modelling result based on investment and dispatch optimisation.
Security of Supply	It is assumed that all power plants have 90% availability	The model will invest in new capacity to secure power supply in all time-segments (Unless price ceiling of 3 Euro/kWh is reached). If price ceiling is reached, the model will shed consumption (brownout).

4 Research question and scenarios analysed

The objective of this study, as mentioned in the introduction, is to better understand the role of thermal biomass plants in balancing a future system dominated by renewable energy, by applying a system perspective. This could be broken down in two main research questions:

- Is biomass attractive for generation of electricity and heat, and will it have a role to **balance the system** in a VRES-dominated future?
- What is the **role of biomass** in the future power and heat sector in a thermal dominated system like Germany?

The approach to answer the questions is to develop a simple scenario framework, with two scenarios to be analysed:

- **Reference scenario**: best estimate of the development of the European power sector;

Reference

- **Biomass+ scenario**: scenario with much more favourable conditions for biomass, in terms of higher $CO2$ price and lower biomass price.

Biomass+

4.1 REFERENCE SCENARIO

In the first scenario, which serves as a reference, the approach was to adopt the best estimation of potential external parameters which affect the system development, based on the information available today and using relevant policy documents as a starting point. The resultant system, optimized by the Balmorel model, should be interpreted as the central estimate of the future development given the information available today and the current commitment of various countries in Europe. Moreover, no specific policy or incentive for biomass is given, outside the existing committed pipeline of projects. The reference scenario reflects a situation where the recent suggestion by the government-appointed commission in Germany to decommission all coal power plants by 2038 is not implemented.

The use of specific assumptions on future electricity demand, fuel prices, CO_2-emission costs (EUA price), technology CAPEX and OPEX is summarised in Table 1 (above) and described more in detail in the Appendix.

4.2 BIOMASS+ SCENARIO

The main idea behind the second scenario, Biomass+, is to assess the role of biomass under very favourable conditions for its deployment. In other words, some assumptions are changed to represent a more supportive landscape for the deployment of thermal biomass plants in the future. This scenario can be interpreted as a "best case" for biomass in the German and European energy system more broadly.

The magnitude of installed biomass fired capacity in the future power system will of course depend on many factors, framework conditions and political decisions. In order for biomass plant to be economical competitive in the power market some factors weigh heavier than others.

With the aim of trying to reflect the system perspective, the following table shows some of the parameters affecting biomass competitiveness in a power or heat market, both in terms of utilization and investments. It has to be noted that in case biomass utilization is increased as effect to a change in a parameter, also the investments in biomass plants will likely increase in a longer time horizon.

Table 4.1 *System Perspective: Impact of various parameters on the competitiveness of biomass.*

Parameter	Effect on:	Outcome
Positive		
Higher Fossil fuel prices	Biomass utilization	↑
Higher CO_2 quota price	Biomass utilization	↑
Higher national biomass targets	Biomass investments	↑
Lower biomass price	Biomass utilization and investments	↑
Specific subsidy scheme or advantageous taxation	Biomass utilization and investments	↑
Negative		
Lower wind and solar cost	Biomass investments	↓
Availability of cheap storage	Biomass investments	↓
More stringent standards and policies on pollutant emissions	Biomass investments	↓
Lower power demand	Biomass investments	↓

In the absence of favourable subsidy schemes or advantageous taxation, which are not part of this analysis, the level of CO_2 quota price and biomass feedstock prices are the two factors that will more heavily impact the competitiveness of biomass units compared to coal-fired or gas-fired generation.

In the framework of Biomass+ Scenario, in order to simulate a higher biomass-use in the energy system, these two parameters are used as a main driver and the following changes made:

- The **CO_2 certificate (EUA) price is doubled** in 2040 compared to the Reference scenario ending at over 100$/ton CO_2 at the end of the period (*Figure 4.1*). This is simulating a more ambitious path toward decarbonization of the power system, thus reducing the opportunity to keep using existing fossil fuel power plants due to the increased cost of generation.

- The **biomass feedstock price is halved** compared to the Reference scenario from 2020 onward (Table X), potentially representing abundant biomass supply or subsidized use for power and heat generation.

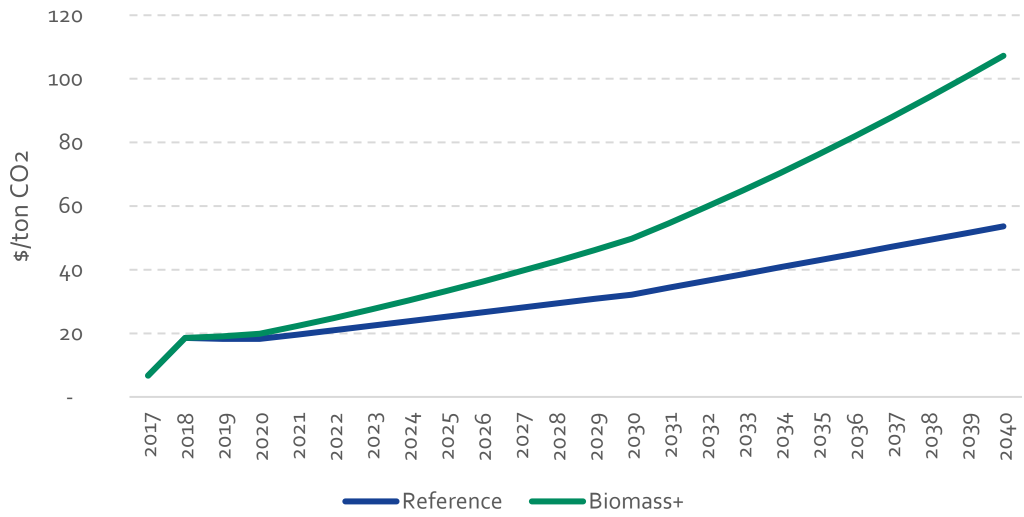

Figure 4.1. Assumption on CO2-price in the Reference and Biomass+ scenario.

It could be debated whether the price level assumed for CO_2 in the Biomass+ scenario is reasonable. While a doubling of CO_2 price in 2040 may seem high, several studies has demonstrated similar or even higher prices of carbon in their analyses. For instance, IEA's World Energy Outlook 2018 [9] "Sustainable Development" scenario reach a price of 140 $/ton in 2040, and ENTSO-E's TYNDP 2018 [10] scenario "Global Climate Action" shows a price of around 110 $/ton. Also, the EU Climate strategy published in November 2018 [8] uses a CO_2 price of 250 €/ton (around 290 $/ton) by 2050 for their 80% CO_2 reduction scenarios.

Prices of biomass feedstock for each individual producer can vary significantly and though the prices used in the Reference scenario are believed to be a reasonable expectation of the average price for biomass fuels, of course prices could be both higher or lower than expected.

Table 4.2. Fuel price assumptions in the Reference and Biomass+ scenarios.

($/GJ)		2017	2020	2030	2040
	Coal	3.3	3	2.6	2.5
	Natural gas	6.5	8	8	8.6
	Fuel oil	8.2	9.5	12.5	11.3
Reference	Wood chips	7.7	7.8	8.3	8.4
	Wood pellets	8.8	10.5	10.6	10.5
Biomass+	Wood chips	7.7	3.9	4.1	4.2
	Wood pellets	8.8	5.3	5.3	5.3

It must be noted that in both scenarios the same characteristics of biomass power plants have been assumed, following indications from a technology catalogue of new power plants published and regularly updated by the Danish Energy Agency [11]. This specific catalogue is chosen due to the high level of detail in the power plant data, the thorough process of data development though stakeholders meeting and involvement of industry experts, and the fact that the data summarizes cost trends around Europe at large. The reason behind the fixed choice of power plant data is that no breakthrough is expected in the design and consequently cost of biomass-fired power plants, being it a quite mature and well-established technology.

Main assumptions on cost and characteristics development are shown in Table 4.3 for wood chip fired units (assumptions for straw- and wood pellet fired units are very similar).

Table 4.3: Technology data for woodchip fired plants.

		2017	2020	2030	2040
Condensing plant	Investment cost (M$/MW)	2.8	2.7	2.6	2.6
	Fixed O&M ($/MW/year)	76.6	76.6	76.6	76.6
	Variable O&M ($/MWh)	2.9	2.9	2.9	2.9
	Efficiency (%)	45%	47%	49%	49%
Extraction plant (CHP)	Investment cost (M$/MW)	2.8	2.7	2.6	2.6
	Fixed O&M ($/MW/year)	95.7	95.7	95.7	95.7
	Variable O&M ($/MWh)	2.9	2.9	2.9	2.9
	Efficiency (%)	45%	47%	49%	49%
Backpressure plant (CHP)	Investment cost (M$/MW)	3.4	3.2	3.1	3.1
	Fixed O&M ($/MW/year)	95.7	95.7	95.7	95.7
	Variable O&M ($/MWh)	2.9	2.9	2.9	2.9
	Efficiency (%)	45%	47%	49%	49%
Boiler	Investment cost (M$/MW)	1.0	1.0	1.0	1.0
	Fixed O&M ($/MW/year)	10.5	10.5	10.5	10.5
	Variable O&M ($/MWh)	3.5	3.5	3.5	3.5
	Efficiency (%)	108%	108%	108%	108%

5 Results and discussion

The section presents results for the two scenarios and discuss the implications of model output with respect to the research questions of the analysis.

5.1 DEVELOPMENT OF THE POWER SYSTEM IN THE ENTIRE AREA

In order to understand the type of energy system in which the analysis is conducted, *Figure 4.2* shows the development of power generation until 2040 for the Reference scenario, in the entire modelled area. It has to be underlined that the amount of capacity and generation from each source is not an input to the analysis, but rather a result of the model optimization of new power capacity and the detailed least-cost hourly dispatch, based on the broader assumptions outlined in Section 2 and in Appendix 1.

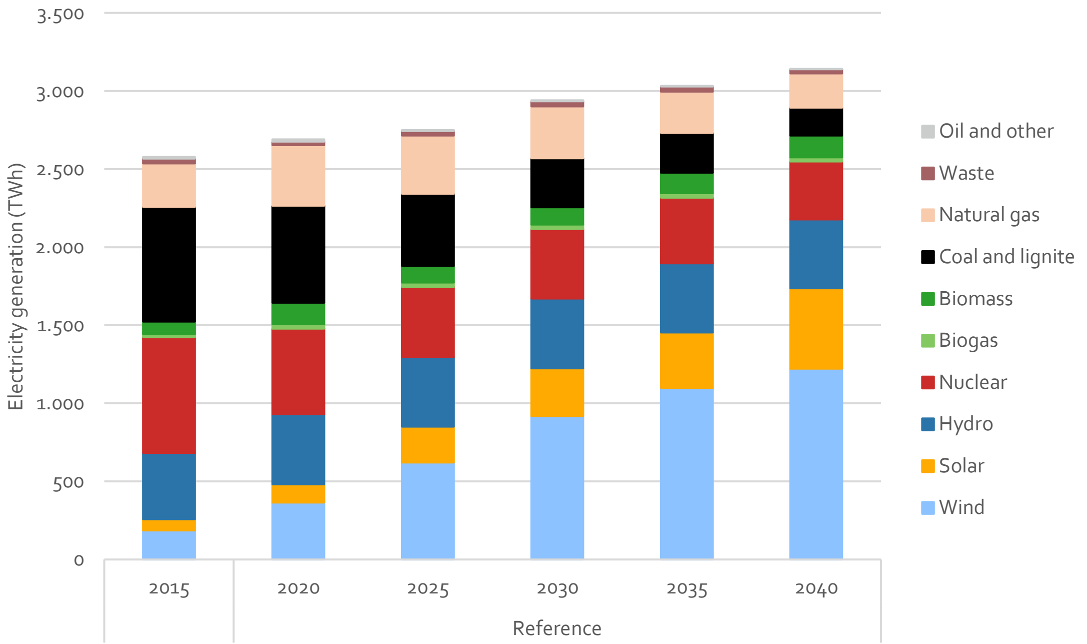

Figure 5.1: Electricity generation for the whole model area given in TWh for Reference scenario.

Two of the main trends that can be recognized in the generation evolution: coal generation is largely reduced in the modelled period, with less than half generation in 2030 compared to 2015, and a surge in solar and wind generation. The total amount of VRES in the system grows more than threefold from 2020 to 2040, reaching a penetration of more than 50% in 2040.

The main driver for the solar and wind advancement is the very low levelized cost of electricity (LCoE), further reduced from today's level by the continuous decline in their cost and the increase in the performance. Toward 2030, the competitive generation cost of a new wind or solar plant can outcompete existing coal power plants, resulting in decommissioning around Europe.

Most of the investment in new capacity in the modelled period are wind and solar plants (790GW, corresponding to around 90% of the total addition), while some natural gas plants (40 GW), biomass (17 GW), biogas and waste (2.5 GW) are also added to the system.

In a Reference scenario, representing the best estimate of the power system development, the market alone will hardly drive any thermal biomass power into the German energy system due to competition from existing fossil fuel plants and new wind and solar. The permanence in the system of this conventional capacity, which is cheaper to operate than building new power plants, limits the room for additional thermal capacity, for example biomass plants, in the system.

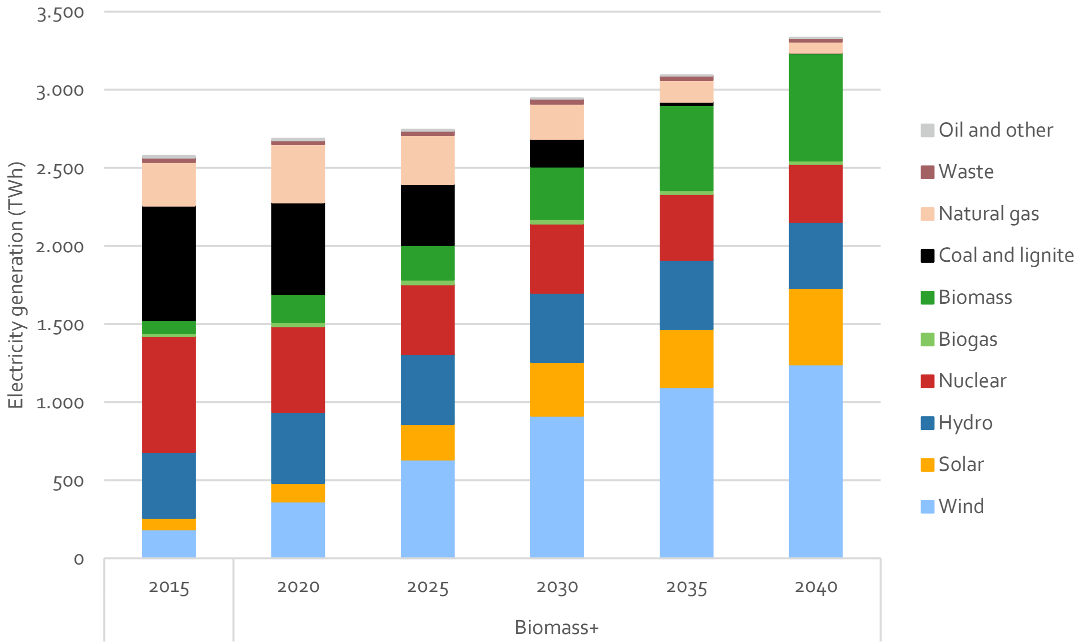

Figure 5.2 Development of power generation in the Biomass+ scenario in TWh for entire modelled area.

In the Biomass+ scenario, presented in Figure 4.3, the development follows similar patterns: large decommissioning of coal plants and system dominated by VRES. However, increase the competitivity of biomass feedstock and the climate ambitions (through a higher CO_2 price) drives a quite significant biomass generation in the system, in particular from 2030 onward, reaching a share of 20% in 2040. Compared to the reference case, additional biomass displaces mainly coal and gas generation, and a small amount of solar power. In facts, by 2040 all coal generation is forced out of the system mainly due to the additional cost of carbon emission. It has to be mentioned that this assumes all coal power plants in Europe are decommissioned in the next 20 years, which might not be realistic especially for Eastern European countries like Poland, which power system is still largely reliant on coal and lignite power plants for the supply of bulk electricity and new power plants have been commissioned in recent years. While the model invests in new biomass capacity it must be mentioned that this could also appear in the form of co-firing or refurbishments on existing coal fired plants. However, specific investment costs associated with this vary significantly from unit to unit and no comprehensible data has been acquired in order to include this in detail in this analysis.

Comparing the generation in 2040 with the one in the Reference scenario also highlights a higher total generation in Biomass+. This is explained by a higher rate of electrification especially of natural gas fired boiler for industry, driven by a high cost of carbon emissions. Therefore, industrial electrification also impacts the role of biomass electricity generation by powering electric boilers in the industry.

To sum up, special framework conditions or low feedstock prices are needed before we see significant investments in thermal biomass power. Moreover, the main barrier for a higher biomass penetration is the generation from existing fossil fuel assets, rather than the competition with VRES power plants.

5.2 ROLE OF BIOMASS IN GERMANY

When looking more specifically at the two scenarios in Germany, the difference is even larger. Very low penetration of biomass is experienced in the reference scenario, with still coal and natural gas providing the dispatchable power needed to balance the system. In the Biomass+ scenario, the share of total generation coming from biomass-fuelled plants is larger than average in the modelled area, with a value of 17% in 2030 and 35% in 2040. However, it is also worth noting that before 2030 the amount of investments in biomass plants is not large, even with the favourable conditions of the Biomass+ scenario.

In the Biomass+ scenario, biomass is largely substituting coal-based electricity generation. This scenario can be interpreted as an example of how the recent suggestion by the government-appointed commission in Germany to decommission all coal power plants by 2038 could be implemented.

The amount of solar power in the German power system is lower in the Biomass+ scenario and most of the reduction in solar generation in the entire modelled area takes place in Germany, which is in fact becoming the largest producer of biomass-based electricity, while solar power is shifted elsewhere.

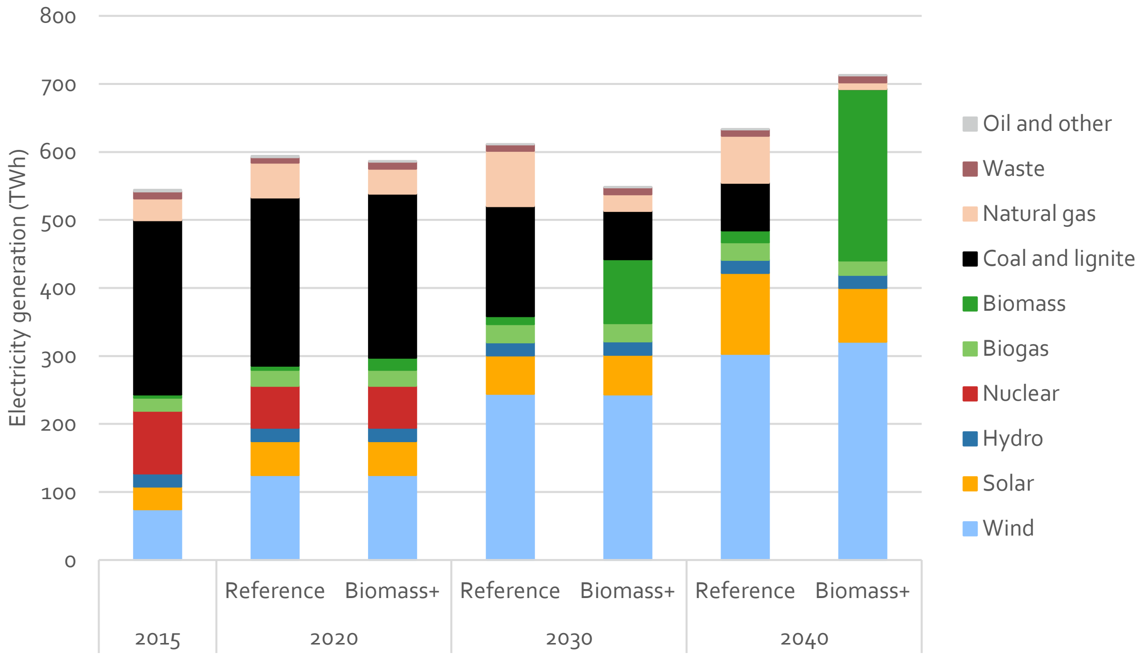

Figure 5.3: Electricity generation for Germany in the two scenarios given in TWh.

5.3 DIFFERENT ROLES OF BIOMASS PLANTS

To assess the role of biomass plants in the system, two indicators are analysed here: the capture price of various plant types and their full load hours.

As for full load hours[2], a pattern emerges with power plants presenting different values across the two scenarios, see Table 4.4. The first thing that stands out is the diverse behaviour of condensing biomass plants between scenarios: from very low values of 300-2000h in Reference, the value

[2] Full Load Hours are defined as equivalent number of hours of production at full (rated) capacity. It is the same measure as capacity factors but expressed in hours instead of percentage. Baseload plants could be defined as having between 6000 and 8700 full load hours.

increases sharply in Biomass+, testifying the different role of condensing plants in the two different systems. On the other hand, even if with a lower magnitude, a similar pattern emerges for combined heat and power plants that increase their annual operational hours from around 5000 hours in Reference to more than 6000 hours in Biomass+.

The role of biomass plants changes from peaking (condensing) or intermediate (CHP) plant to baseload plant when conditions become very favourable in terms of feedstock price and other baseload technologies are pushed out of the market due to high carbon price.

Table 5.1: Full load hours of Biomass plants in the two scenarios for Germany.

Full load hours*		2020	2025	2030	2035	2040
Reference	Backpressure	5.500	5.400	5.300	5.100	5.000
	Condensing	300	2.600	2.100	3.500	4.500
	Extraction	5.900	4.900	5.500	5.800	5.800
Biomass+	Backpressure	6.100	7.000	6.900	6.400	6.100
	Condensing	7.300	7.200	7.000	7.000	7.200
	Extraction	-	6.500	6.500	6.500	6.600

This is confirmed by looking at capture prices. The capture price of a technology (or group of technologies), also referred to as market value, is the average selling price of electricity produced by the technology in the market and it is often compared to the average electricity price[3]. A capture price higher than the average price indicates a technology that is able to produce when electricity is most valuable, i.e. in periods of higher electricity prices; this is often the case for peaking technologies. On the other hand, technologies like wind and solar most often have values below average price, since they cannot be dispatched freely and when they produce the price in the market is decreased by high RE generation.

When looking at capture prices for Germany, it can be noted that CHP plants (extraction and backpressure) sells power more or less around the average market price, due to their high amount of running hours. Condensing plants, instead, behave like a peaking in the Reference scenario, i.e. selling power in hours with very high price, while behaving more like a baseload plant in the Biomass+ scenario.

An additional thing to note is that from 2020 to 2040 there is a general trend for all power plants of increasing capture price compared to average electricity price. This is due to the fact that with a lot of wind and solar in the next future, power prices become more polarized: very low price when abundant VRES are dispatched and higher price when there is a lack of wind and solar. This increases the relative capture price of dispatchable plants like biomass.

[3] Capture price is calculated as total revenue for a particular group of technologies in a year divided by their total generation in that year and it is an indication of how valuable is the electricity sold by the technology/group of technologies in the market.

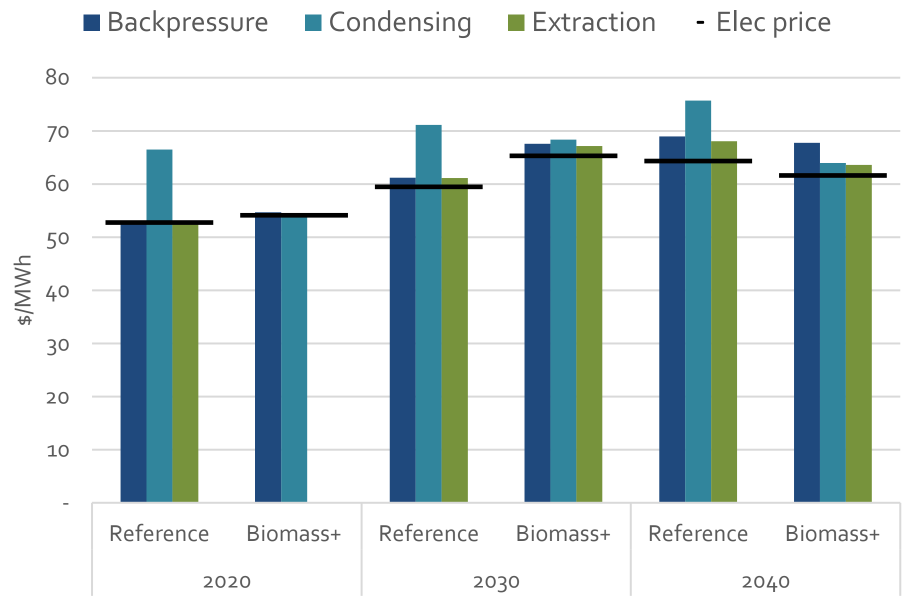

Figure 5.4: Capture prices vs average power prices for the two scenarios for Southern Germany.

5.4 AN OVERVIEW OF LOAD DISTRIBUTION AND SYSTEM NEEDS

An intuitive way to visualize load distribution and system requirements is using load duration curve. A load duration curve shows the load in each hour of the year in a descending order, making it possible to evaluate the need for different type of power plants: baseload, mid merit and peakers. Variable renewable energies like wind and solar, not being dispatchable are usually subtracted to the load and the so-called residual load curve computed instead; it represents the load (residual) which has to be served by other dispatchable generation. An example of load and residual load duration curves is shown in Figure, representing the situation in the modelled area in 2015.

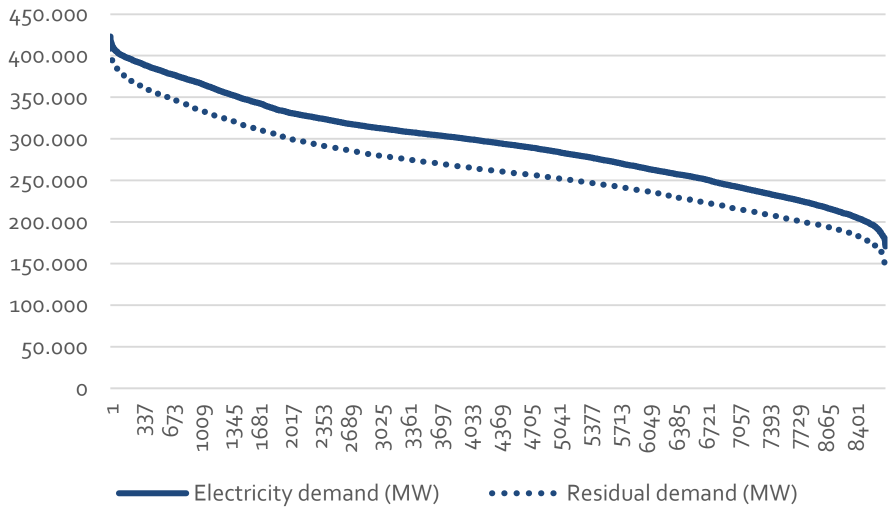

Figure 5.5 Load and residual load duration curves for modelled area in 2015.

With increasing shares of VRES in the system, the load curve becomes steeper reducing the room for baseload, but still requiring similar levels of peak capacity available to cover those hours of the year with high load but low wind and solar generation. Further complexity is added by flexibility resources both on the supply side and in the consumption side, like electricity-to-heat technologies, storage and electric vehicle demand for charging. These resources, while increasing total demand, add or increase load in hours of high wind and solar generation, e.g. filling up storages, charging EVs etc., ultimately reducing the need for peak technologies. As shown in Figure 4.7, the total peak demand in the modelled area in 2040 is around 580 GW, but only 330 GW of this is not already covered by storage unloading, wind or solar, ultimately reducing the need for dispatchable power plants. In the scenario Biomass+ in 2040, baseload requirements are covered by nuclear power and biomass, while other sources (hydropower, natural gas, electricity storage) takes care of most of the flexibility needs and operate as peak producers.

In the Biomass+ scenario, biomass power units are only utilising their flexibility resources to a minimal extent. The reason is relatively straight forward and concerns economy: biomass plants are relatively expensive and need to maximise operating hours to be feasible. In practical operation however, flexibility can give increased income in the balancing- or ancillary service markets (Balancing and ancillary service markets are not explicit part of the modelling).

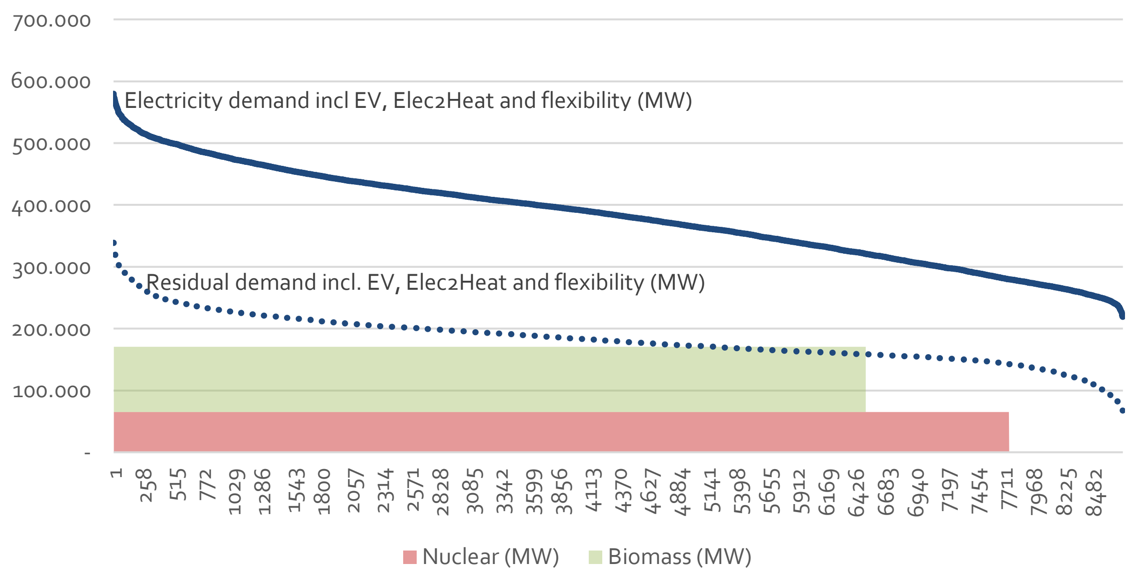

Figure 5.6: *Electricity demand and residual demand (wind and solar generation subtracted) for the whole model region in 2040 for the Biomass+ scenario.*

If we focus on Germany (Figure 4.8), it can clearly be seen that all the baseload requirement is taken care of by biomass plants. However, given the steepness of the residual load duration curve (very high amount of wind and solar), not all the electricity production can be accommodated, therefore part of it is exported to neighbour countries, given the central position of Germany in the European power system and its high degree of interconnection. In case the German power system was less interconnected, the room for biomass, which needs a certain minimum amount of full load hours to be competitive, would have been lower.

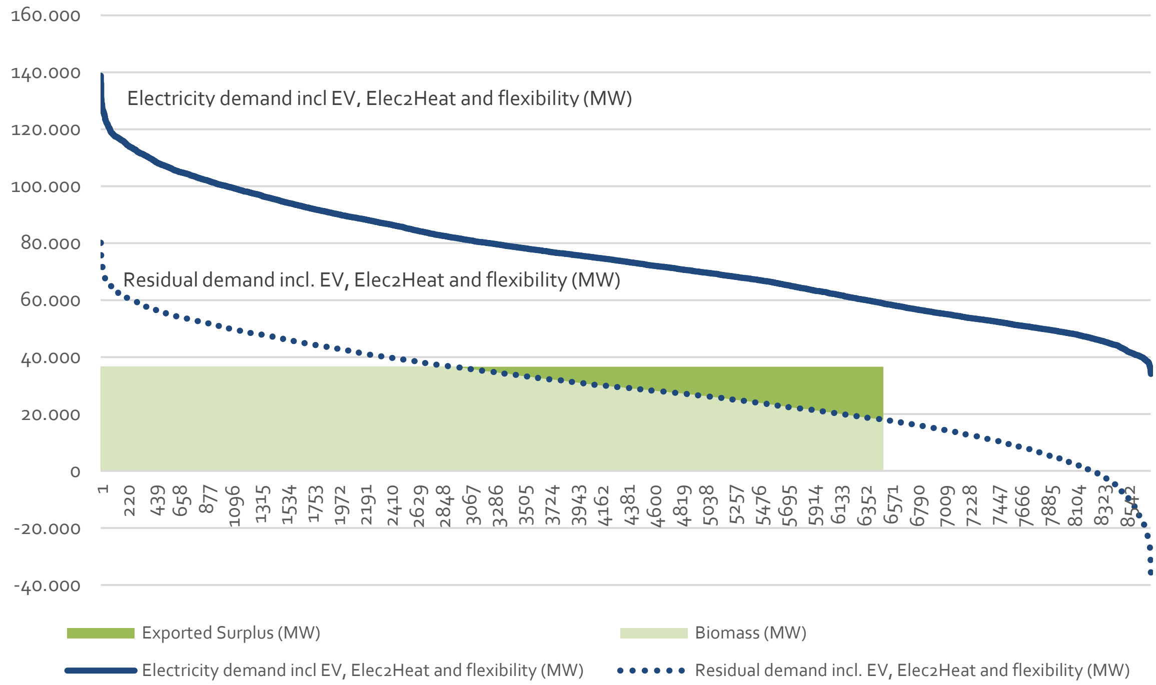

Figure 5.7: *Electricity demand and residual demand (wind and solar generation subtracted) for Germany in 2040 for the Biomass+ scenario.*

5.5 THE ROLE OF DISTRICT HEATING IN THE POWER PLANT ECONOMY

The access to heat markets is the predominant limit for biomass CHP plants as long as the economic circumstances favour these. As shown in Figure 4.10 by 2040 the heat marked is saturated with biomass fired CHP in the Biomass+ scenario. With favourable conditions for biomass fired generation the revenue from heat sales makes biomass CHP the main source of heat generation. In this analysis this revenue is shown based on marginal generation costs and not on actual heat supply contracts where prices are based on negotiated agreements, typically with a longer time perspective.

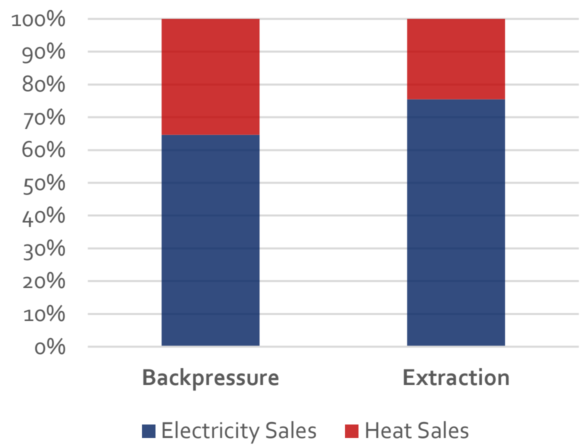

Figure 5.8: *Average ratio of revenue for heat and electricity sales based on marginal generation costs.*

If splitting up revenues from power and heat for biomass CHP plants, it can be seen how heat revenues are an important part of individual plants economy. Across all scenarios and years simulated, heat revenues averages between 25% (extraction units) and 35% (backpressure units) of the total sales.

Figure 4.10 gives an overview of the supply of heat in district heating areas in Germany[4]. The amount of district heating demand supplied by biomass is relatively low in the Reference scenario, representing less than 15% in 2040. In the Biomass+ scenario, instead, almost the entire supply of heat is covered with waste, solar and biomass, with the latter representing around 75% of the total. Of this, only 3% is covered by boilers, underlining the importance of CHP plants in the supply. The model assumptions include some constraints on minimum levels of biogas consumption and municipal waste incineration, and these cannot be displaced by additional biomass.

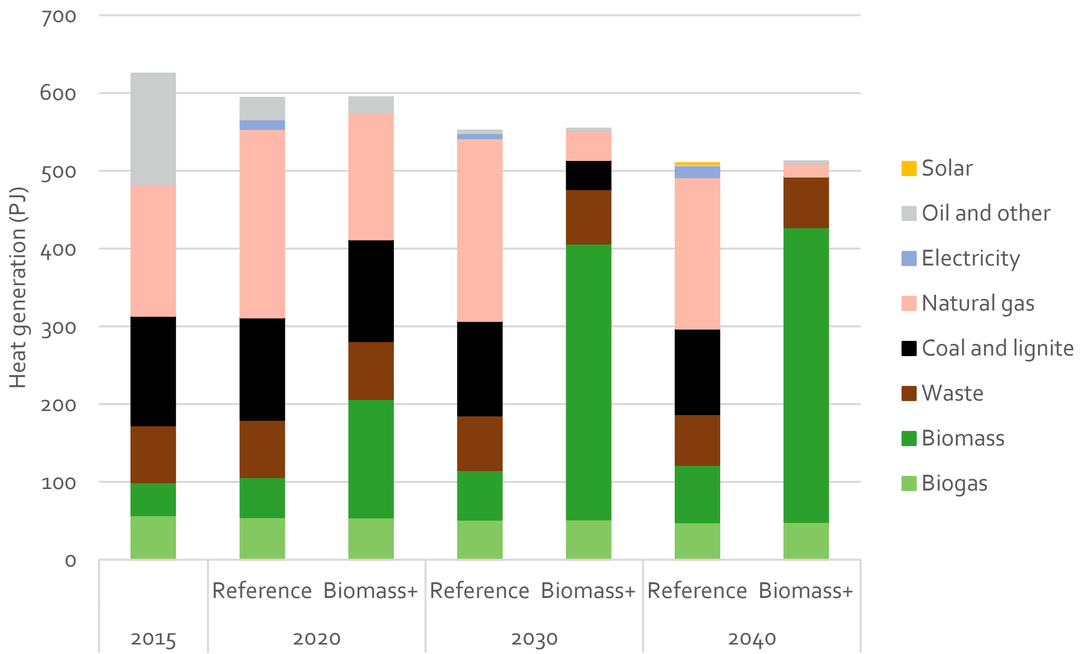

Figure 5.9: District heating generation for Germany for the two scenarios given in PJ.

It is evident that, considering also the aforementioned importance of heat revenues for individual plants, the total amount of district heating demand that can be supplied by biomass CHP becomes an actual barrier for higher penetration of biomass in the power sector.

[4] Only the largest district heating areas in Germany are represented in the model.

6 Conclusions

Two scenarios, *Reference* and *Biomass+*, have been simulated using the Balmorel model for the European energy system with focus on Germany as a part of this system for the years 2020, 2030 and 2040. The Balmorel model enables analyses of the evolution of the combined heat and power sectors by calculating the least-cost solution for investments and dispatch by means of linear optimization.

The Reference scenario, characterized by current preconditions and assumptions that represent the best estimate of future demand, fuel prices, CO_2 costs, investment costs, etc. shows very limited biomass-based electricity generation capacities and generation in 2040 in Germany and Europe more broadly while coal still plays a significant role. Not only biomass, but all technologies in the power sector will be challenged by increasing competitiveness of wind and solar generation.

The model results show that there is a need for "firm and dispatchable" power" in the electricity system. Gas, coal, biomass and to a certain extent nuclear technology are in this category. However, due to increased utilisation of hydropower, increased flexibility in demand and increased cross-border market- and sector integration, the demand for firm and dispatchable power technologies will decrease. If storage technologies gain momentum – this will drag in the same direction.

In the Biomass+ scenario, a more favourable framework for the deployment of biomass has been simulated by assuming two main drivers compared to the reference: a doubled CO_2 price by 2040 and a biomass feedstock price lowered to half from 2020 onward. The calculations for 2040 show that a substantial investment in biomass-based generation capacity has taken place and that this capacity is allowed a high number of annual operational hours.

It can be concluded that the existing and estimated future market conditions alone will not be able to drive any substantial amount of thermal biomass power into the German energy system up to 2040 due to competition with existing fossil fuel plants and cheap wind and solar investments. Special framework conditions and/or low feedstock prices are needed before significant investments in thermal biomass power capacity and a high number of operational hours will take place.

Given high CO_2 prices and low feedstock prices, thermal biomass plants substitute coal and gas and some PV generation in Germany. In case of enabling conditions for biomass to be more competitive, the role of biomass power plants is to provide baseload generation in substitution to other fossil fuel plants like coal and lignite, while system flexibility services would be primarily delivered by more responsive hydropower, pumped and other electricity storages, and gas-fired power units.

Biomass is in direct competition with coal and natural gas. CAPEX and OPEX ratios between these technologies are key. Higher CO_2 price and lower biomass prices (or corresponding incentives) will increase competitiveness of biomass technologies, as shown in Figure 4.11.

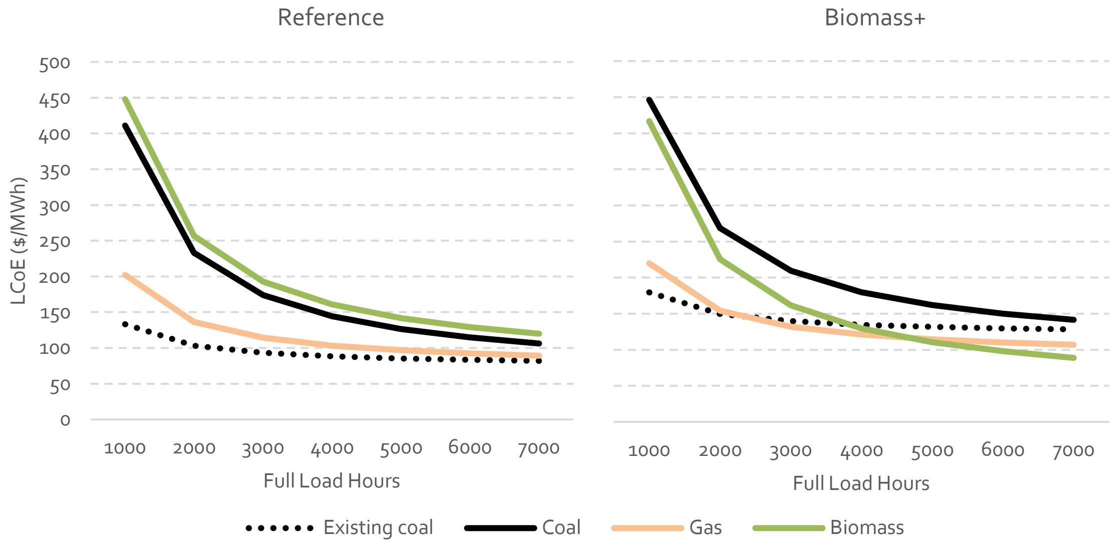

Figure 6.1: *Generation cost (LCoE) at different utilization levels for new gas (combined-cycle), coal and biomass power plants, and comparison with the cost of running existing coal plants in the two scenarios in 2040.*

Policy decisions at country level affect the development of the power system. For example, during the completion of this analysis, a government-appointed commission in Germany suggested a complete coal phase-out by 2038. The Reference scenario represents a situation where this suggestion is not followed up by a formal decision while the Biomass+ scenario can be seen as an example of a situation where the proposed decommissioning actually takes place.

Another example of how policy affects the power system can be seen in the scenario analysis. There is a need for dispatchable power plants in the system and given the contemporary decommissioning of nuclear plants outlined in the Energiewende, biomass plants could possibly have a larger role than originally anticipated in the reference scenario.

The calculations show that in a situation with favourable conditions for biomass fired capacity, then biomass CHP will play the dominant role in the district heat supply.

It might be debated whether the price levels assumed for CO_2 and biomass in the Biomass+ scenario are reasonable. Many studies demonstrate high prices of carbon in their analyses and the fuel prices could be the result of a mix of low prices and/or subsidies.

Regardless of the actual level of carbon pricing or feedstock price assumed, the study shows that strong drivers are needed to see a large role for biomass in a future thermal-dominated power system like in Germany and more broadly in Europe.

7 References

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[3] Fraunhofer ISE, “Energy Charts,” 2019. [Online]. Available: https://www.energy-charts.de. [Accessed: 15-Feb-2019].

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[5] Reuters, “Germany to phase out coal by 2038 in move away from fossil fuels,” 2019. [Online]. Available: https://www.reuters.com/article/us-germany-energy-coal/germany-to-phase-out-coal-by-2038-in-move-away-from-fossil-fuels-idUSKCN1PK04L.

[6] AGFW, “District Heating in Europe and Germany.” 2017.

[7] RenewablesNow, “Low interest in 2nd Biomass tender.” [Online]. Available: https://renewablesnow.com/news/low-interest-765-mw-of-awards-in-2nd-german-biomass-tender-627207/.

[8] European Commission, “A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy,” 2018.

[9] International Energy Agency, “World Energy Outlook 2018,” 2018.

[10] ENTSOE, “TYNDP 2018 - Europe’s Network Development Plan to 2025, 2030 and 2040,” 2018.

[11] Danish Energy Agency, “Technology data,” 2018. [Online]. Available: https://ens.dk/en/our-services/projections-and-models/technology-data.

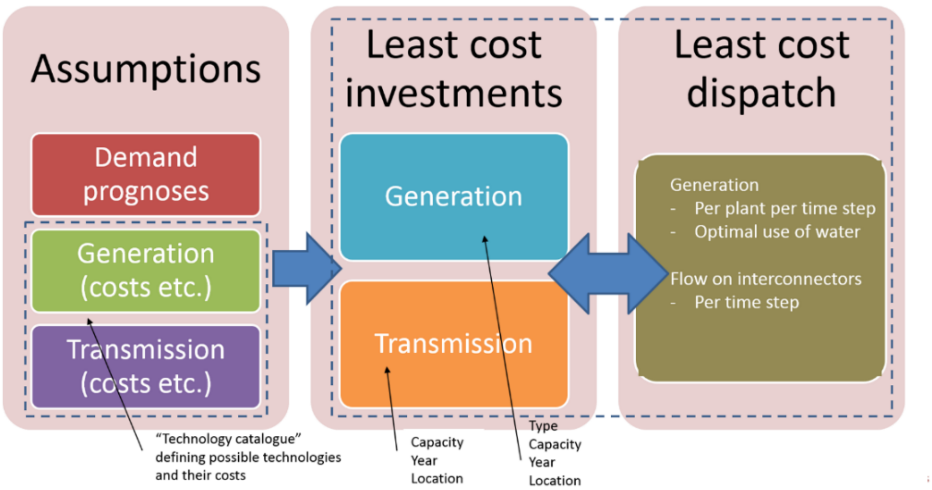
Appendix 1 - The Balmorel model

THE BALMOREL MODEL

Balmorel is a detailed techno-economical partial equilibrium model suited for analyses of electricity as well as combined heat and power markets. It is capable of both investment and dispatch optimization. In investment mode, it is able to simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies as well as transmission capacity between predefined regions.

In dispatch optimization mode, it determines the market optimal utilization of available generation and transmission capacity. It is capable of both time-aggregated as well as hourly modelling, which allows for a high level of geographical, technical and temporal detail. It is particularly strong in addressing the interdependency between heat and electricity production of combined heat and power (CHP) generators.

The mathematical principle behind Balmorel is based on finding a least cost solution for the dispatch and investments within the regarded interrelated electricity and district heating markets. Doing so, Balmorel takes into account developments of electricity and heat demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, spatial and temporal availability of primary renewable energy, etc.



Both societal and stakeholder perspectives can be analysed based on the models results.

The representation of the transmission grid

Transmission lines are represented by the total capacity available to the market between bidding areas (net transfer capacity).

Detailed representation of heat markets and combined heat and power

The model allows for detailed simulation of heat market, which is particularly important in countries and regions, where combined heat and power is noticeable.

Two technology types represent CPH units; extraction units and backpressure units. The capacities in the model are given as net capacities for either electricity or heat. For extraction units, the capacity is given as the electrical capacity in condensing mode; while for backpressure units it is given as the electricity capacity in co-generation mode. In full cogeneration mode at CHP units, the Cb-value specifies the ratio between electricity and heat. For extraction units, the Cv-value specifies the loss in electricity when producing heat for maintained fuel consumption. The fuel efficiencies in the model are for CHP units given as the fuel efficiency in condensing mode for extraction units and the total fuel efficiency in CHP mode for back-pressure units.

The model also includes heat only generation technologies without simultaneous electricity generation, for example heat only boilers and electricity-to-heat units (heat pumps, electric boilers). With increasing shares of renewable in power systems, electricity to heat technologies become important for system integration.

Investment module

The model has a technology catalogue with a set of new power generation technologies that it can invest in according to the input data. The investment module allows the model to invest in a range of different technologies including coal power, gas power (combined cycle plants and gas engines), straw and wood-based power plants, wind power (on and off-shore) and solar PV. The model is also able to rebuild existing thermal power plants from the existing fuel to another. At a lower cost than building a new power station, the model can choose to rebuild a coal-fired plant to a wood pellets or wood chips, and convert natural gas fired plant to biogas.

The technology assumptions develop from now to 2050, that meaning costs and efficiencies develop according to learning curves for the specific technology. Technology assumptions are largely based on the Danish Energy Agency's technology catalogues (https://ens.dk/en/our-services/projections-and-models/technology-data)

Decommissioning of power plants

The decommissioning of thermal power plants can happen both exogenously and endogenously in the model. The exogenous approach is based on data about the year of commissioning of power plants and assumptions about typical technical lifetime. Moreover, the model can decide to decommission a power plant when it is no longer economical profitable to operate (endogenous decommissioning).

GENERAL CHARACTERISTICS

Geographical scope

The Balmorel simulations are carried out over a model area which comprises the Baltic countries, the Nordic countries, Poland, Germany, the Benelux, Great Britain, Ireland, France, Switzerland, Austria, Czech Republic and Italy. But the Balmorel model is also represented for many other countries around Europe and the rest of the world.

Exogenous capacity

Development of the existing generation capacity is subject to uncertainty. The reason is that similar to new investment, the lifetime of existing capacities is subject to economic optimisation and thus dependent on the development of electricity prices. However, other factors also play a role, and these can be harder to reflect in the model optimisation. They include: Environmental legislation on emissions effectively ruling out older power plants; various national subsidies to support certain power plants or type of power plants due to either concerns about the security of supply or national priorities (e.g. importance of power plants for regional economy and labour), optimisation of fixed cost as a result of changing operational patterns.

The overall approach to the development of existing capacities is that known and certain phase-outs are implemented exogenously, while the remaining capacity is held constant, and the lifetime is subject to economic optimisation (power plants have to recover fixed cost). Wind and solar capacity have relatively low fixed operational cost and are therefore assumed to be decommissioned after the end of the technical lifetime.

Endogenous investments and decommissioning

The capacity in the power system develops according to the least cost optimisation of the Balmorel model. The model invests in generation capacity if it is profitable, and decommissions capacity if it is not, from a power system perspective. The model both invests and decommissions myopically, i.e. only based on the information of the given year, not taking into account estimates for the future. This applies to parameters such as fuel and CO_2 prices.

- **Investments:** The model invests in a technology when its projected annual revenue can cover all costs including capital costs, fixed O&M. The model investments have been allowed after 2017, the base year of the model runs.
- **Decommissioning:** The model decommissions a technology when the revenue can no longer recover fixed O&M. Exogenous capacity is kept constant (except if better data for expected decommissioning year is available) unless it is decommissioned by the model. The model has been allowed to decommission capacity after 2020.

DETAILED ASSUMPTIONS

CO_2 price

The CO2 price for the majority of European electricity and district heating plants is determined in the EU Emissions Trading System (ETS), and thus price developments in the EU quota market is determining the CO2 emission costs for the fossil-based generation units. The EU has a goal of reducing greenhouse gas emissions by 80-95% by 2050. The power sector has a large potential for CO2 reductions, and it is therefore expected that this sector will be one of the largest contributors to reductions in CO2 - probably up to 100 % by 2050. By 2030, the EU has set a goal to reduce CO2 emissions by 40% compared to 2005, 43% in the quota sector.

Historically there has been a significant surplus of CO2 quotas, which has meant that the CO2 price has been low for several years. But on 27 February 2018 the EU Council formally approved the reform of the EU emissions trading system (ETS) for the period after 2020. The revised ETS directive is a significant step towards the EU reaching its target of cutting greenhouse gas emissions by at least 40% by 2030, as agreed under the EU's 2030 climate and energy framework and fulfilling its commitments under the Paris Agreement. The implemented market reforms seem to have had an impact on the market and have led a significant price increase in 2018. So far, the price has now risen to over 20 EUR/ton (see *Figure 4.12*)

Figure A.1: Historical prices for CO2 in the EU quota market[5].

In the longer run the CO2 prices are based on ENTSO-E's TYNDP 2018 "EUCO 2030" scenario with a CO2 price of 27 €2015/ton by 2030[6]. This corresponds to the EU Commission's CO2 price needed to reach the EU goals for CO2 emission reductions (described above). These were published in November 2018 in the "In-Depth analysis in support of the commission communication com (2018) 773". Going beyond 2030, the CO2 price is based on ENTSO-E's TYNDP 2018 "Sustainable transition 2040" scenario reaching a price of 45 €2015, see the prices below.

[5] Source: https://markets.businessinsider.com/commodities/co2-emissionsrechte

[6] https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/Scenario_Report_2018_Final.pdf

	CO2 emssions price ($/ton)
2017	6,7
2020	18,2
2025	25,2
2030	32,2
2035	42,9
2040	53,6

Power demand

The development of electricity demand in the modelled area is mainly based on ENTSO-E's scenarios for the TYNDP 2018. For 2020 and 2025, the Best Estimates (BE) are applied. For 2030 and 2040 demand is based on the Sustainable Transition (ST) scenario, which is further extrapolated out to 2050.[7]

The electricity demand assumed for future years accounts for demand for:

- Individual heating
- Electric vehicles
- Electricity use for space heating
- Electricity for industrial electrification (e.g. for process heat in industry)
- Electricity for district heating

Electricity use in district heating and for industrial electrification is determined endogenously in the model simulations and depends on model optimisation. For district heating, the use of electricity is one of the options available to the model to meet district heating demand, in addition to fuel-based technologies (combined heat and power or district heating boilers).

An electrification potential for industrial electrification is defined, which can be supplied using electricity or fuel-based heat generation. The estimated potentials are based on statistics for the share of industrial energy services supplied by oil, gas and coal.[8] We assume that by 2030, up to 50% of this identified potential can be supplied by electricity, reaching 100% in 2050.

Figure 4.13 shows the development of total power demand between 2015 and 2040, split by the different types of demand. Parts of the demand projection are subject to model optimisation and are therefore a result of the modelling rather than an exogenous assumption.

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[7] The TYNDP scenarios also include a EUCO (European Commission) scenario for 2030. However, the assumptions on electricity demand for 2030 do not match developments in the Best Estimate scenarios towards 2020 and 2025. Applying the EUCO scenario for 2030 would therefore imply unrealistically rapid changes in electricity demand between 2025 and 2030.

[8] Data based on Mantzos L. et al; *JRC-IDEES: Integrated Database of the European Energy Sector - Methodological note*, EUR 28773 EN, Publications Office of the European Union, Luxembourg, 2017, ISBN 978-92-79-73465-6, doi:10.2760/182725, JRC108244. Energy service defined as "usefuel energy demand" in the publication.

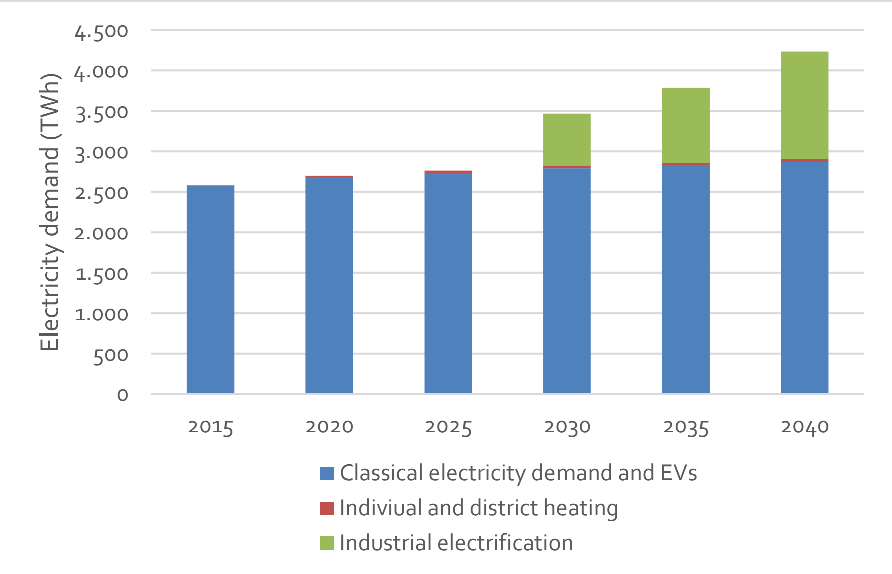

Figure A.2: Electricity demand by type in the modelled area[9] given in TWh.

Demand flexibility

Demand flexibility (demand response) can be an important measure for integration of renewable energy in the power system. However, current experiences with demand flexibility are limited and projections are highly uncertain.

As a cautious assumption, it is assumed here, that 10% of the average nominal demand throughout the year is flexible and can be shifted in time by up to 4 hours. This leads to a demand response capacity of 27 GW by 2050 and the option to "store" 108 GWh. Additional demand flexibility related to electric vehicles is also included.

Heat demand

District heating areas with related heat demand is modelled for selected countries: the Baltic countries, the Nordic countries, Poland and Germany.

[9] Note: Parts of the demand projection are subject to model optimisation and are therefore a result rather than an exogenous assumption.

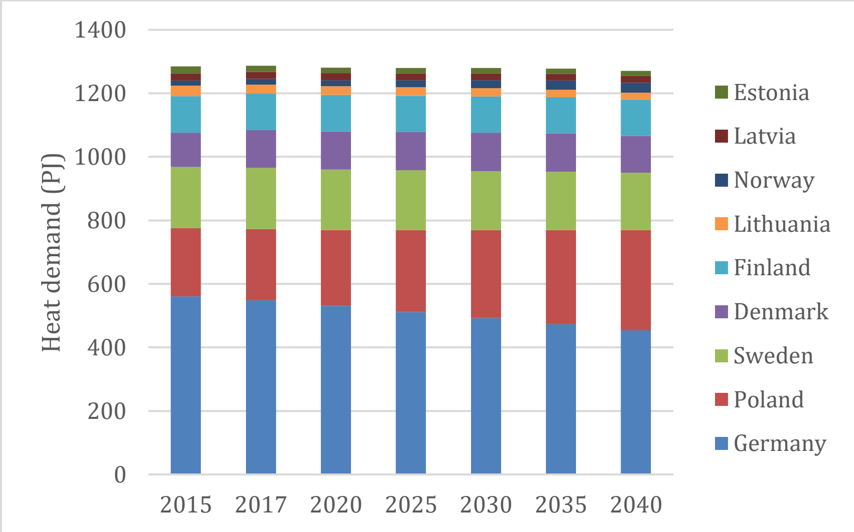

Figure A.3: District heat demand by country included in the modelled area given in PJ.

Renewable energy policies

For each country in the modelled area a minimum level of renewables deployment is anticipated to reflect the effect of climate and energy policies at both national and EU levels. The minimum levels of renewable deployment, which are specified in the model for each country and for each technology out to 2030, are set equal to the deployment levels given in ENTSO-E's "Sustainable Transition" scenario.

Fuel prices

This section describes the methodology of the assumed fuel price projections used in this project.

Forward markets

Market prices are true to the extent that market participants engage in transactions at quoted prices. Forward markets quote prices several years into the future, however there is very limited trading just a few years out. This means that beyond, say five years (depending on the particular commodity), the market price is not an expression of what buyers and sellers expect to eventually pay. In the short-term, however, the forward markets are more liquid, meaning that it is with high likelihood that a transaction partner can be found to trade near the quoted market price.

Long-term equilibrium

The long-term development of fossil-fuel prices are driven by underlying factors such as the global macroeconomic development, technological development and development of resources. While highly uncertain, these factors are best taken consistently into consideration through energy system models, which calculate long-term equilibria. While we do not trust the accuracy of these projections, there is consistency between their underlying assumptions which provides an understanding of their bias.

Convergence of views

In general, the view is adopted that in the short-term the markets are right. In the long-term, the global energy system models are more likely to be right. Therefore, a method is adopted using a gradual conversion between these views.

IEA's "World Energy Outlook 2017" (WEO) publication provides the basis for long-term fossil fuel price projections. It has been chosen to use prices from the "Sustainable Development" scenario, which provides somewhat higher prices than the middle scenario from IEA (New Policies). This has been done for two reasons. Firstly, IEA's "New Policies" scenario has a historical underestimation of technological progress. Choosing this main scenario, will likely lead to the underestimation of cost competitiveness of RE technologies. Secondly, with the climate agreement in Paris, choosing the "New Policies" scenario might lead to an overestimation of fossil fuel demand and related prices.

The fossil fuel prices are based on updated forwards from September 2018 used until 2020. From 2020 to 2030 prices converge to WEO long term prices. The forward prices and WEO are used to arrive at CIF prices which are then subject to a small price add-on in order to produce price "at plant". This price add-on is based on historical statistics for distribution, transport, refinery cost etc., using a method developed for the Danish Energy Agency[10].

A similar approach is used for biomass price projections. In recent years European biomass markets have continued to mature, and for wood pellets in particular, there are now available forward prices that appear to reflect current market conditions. Short-term prices are based on these forwards converging towards long-term equilibrium market prices. The long-term prices are calculated using a model Ea Energy Analyses developed for the Danish Energy Agency based on statistics for both domestic and imported raw biomass prices, transportation and processing cost, shipping rates, port fees and other relevant cost elements and projections. Fuel prices are indicated "at power plant" below.

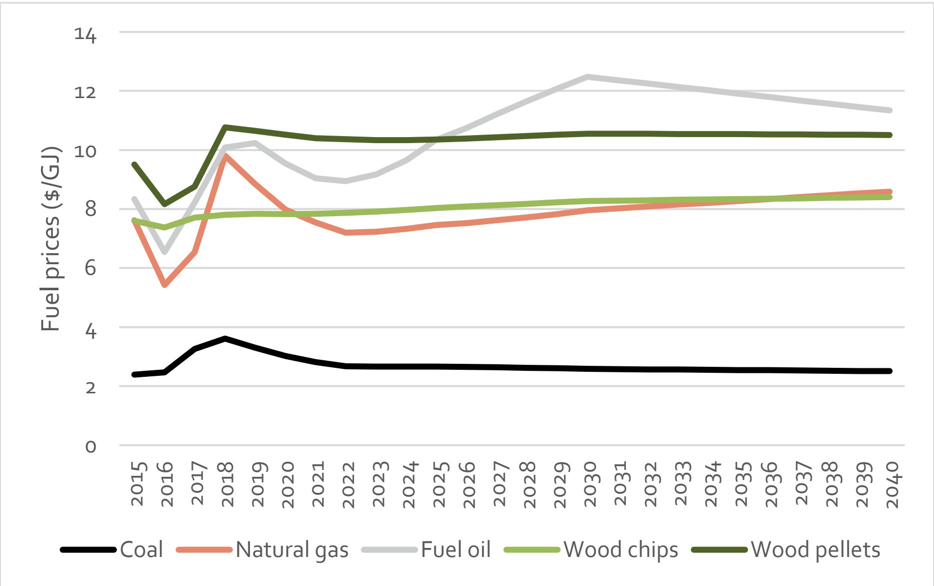

Figure A.4: Fuel prices at plant given in $/GJ.

[10] More information can be found on: https://ens.dk/service/fremskrivninger-analyser-modeller/samfundsoekonomiske-analysemetoder

RES shares

The assumptions on renewables policies and fuel and carbon prices ensure power sector developments consistent with achieving a minimum overall renewable energy share of 27% in the EU by 2030, assuming that performance in other sectors is consistent with ENTSO-E's Sustainable Transition scenario. The decarbonisation of the power market beyond 2030 is driven by further increases in CO2 prices and continued reductions in technology costs.

In June 2018, the European Commission, the European Parliament and the European Council agreed to increase the renewable energy target to 32% with the possibility of an upward revision in 2023. Given the support for renewable generation provided by the assumed trends in fossil fuel prices, CO2 prices and technology costs, the modelled development of the power system might well be able to support this share. However, determining renewable energy use as a share of final energy consumption is not possible within the framework of this project since only the power and district heating sectors are covered by the analysis.

The resulting shares of RES-E in the different countries are a result of the model optimisation under the given assumptions.

Nuclear power

A fixed development of nuclear power generation capacity is assumed in all scenarios reflecting national policies and decided plans.

Development of the transmission grid

Towards 2030, the development of the transmission grid in the modelled area is based on the ENTSO-E's Ten-Year Network Development Plan 2016. After 2030, there are no firm plans for expansion of the European transmission grid, yet further strengthening of the grid is likely to become an important means to integrating high shares of variable renewable energy. To account for this, the model is allowed to invest in additional transmission capacity in both existing and new connections and will do so if found to be economic viable.

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Further Information

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