Review of the Regulatory Environment for CHP

Identification of Relevant Markets

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Internal Report

Authors (in alphabetical order):

Elnaz Abdollahi, José Pablo Chaves-Ávila, Timo Gerres,
Paolo Mastropietro, Pablo Rodilla, Yelena Vardanyan

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[1] PU = Public

PP = Restricted to other programme participants (including the Commission Services)

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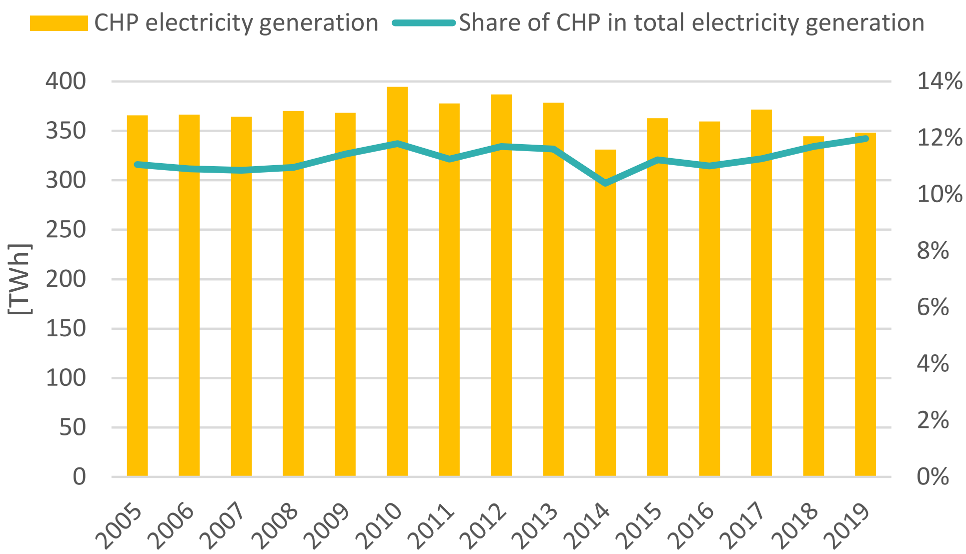
Executive Summary

Combined Heat and Power (CHP), or cogeneration, is a technology that allows the joint production of electricity and thermal energy, thus significantly improving the efficiency of the process. Nonetheless, CHP is a "label" that encompasses many technological solutions, energy management approaches and final uses. Furthermore, cogeneration is a technological solution that heavily depends on local conditions, in terms of climate, industrial development, availability of energy sources, and authorisation processes. The broad heterogeneity of combined heat and power and its dependence on the local conditions are two factors that significantly affect the regulatory environment on cogeneration. In fact, it is not easy to find policies able to promote the whole spectrum of technological solutions and final uses included in the "CHP label". On the other hand, the reliance on local conditions fostered regulatory approaches that left most decisions to local or national authorities, resulting in very different outcomes within the European geography.

Considering the European Union as a whole, the cogeneration sector is in a phase of stagnation. The chart hereunder shows the electricity generation from CHP units and their share in the total electricity generation. In the last two decades, the share of CHP in electricity generation has oscillated between 10% and 12%, without any identifiable trend.



In absolute terms, Germany has by far the largest CHP sector in Europe, followed by countries from both Northern (The Netherlands, Poland, or Finland) and Southern Europe (Italy and Spain). However, when analysing the share of CHP in total electricity generation for each Member State, it is easier to identify a trend, with higher shares in those Member States where the demand for heat is higher due to climatological reasons, although climate is not the only driver for CHP development.

This report presents a detailed assessment of the EU policy regarding CHP (section 1), encompassing the 2004 CHP Directive, the 2012 Energy Efficiency Directive, the three Energy Packages that shaped the Internal Energy Market, the Clean Energy Package and some of the most relevant legislation regarding biomass use. Although European institutions have always recognised the pro-efficiency capabilities of cogeneration, CHP has been considered just as a tool to achieve energy efficiency, not as a target itself. From the CHP Strategy up to the Clean Energy Package, European regulation has

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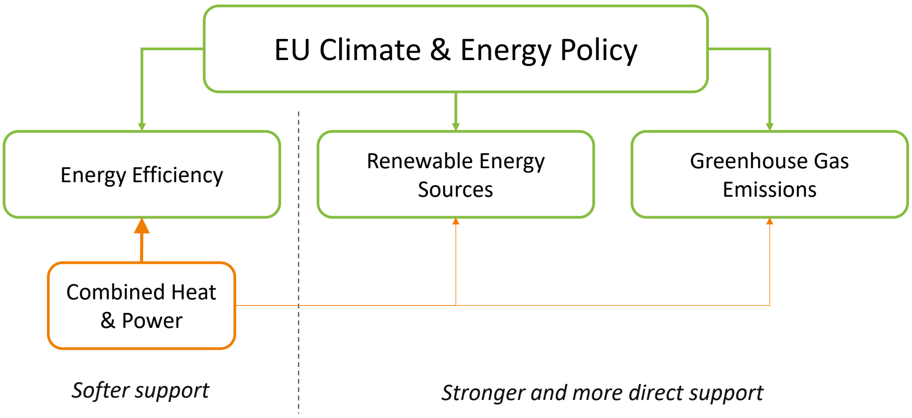
historically had a soft approach. It did not provide binding targets and left most of the policy implementation to the national level. The result is a patchwork of different legislations that increased the risk perceived by investors.

The deployment of CHP has also been hampered by a soft approach on energy efficiency in general. Among the three main elements of the European climate and energy policy, energy efficiency, renewables, and reduction of greenhouse gases, the former always received a different treatment, starting from the 20-20-20 policy, which set binding targets for renewables and emissions, but not for energy efficiency. CHP is a technology that can contribute to all the above-mentioned elements, but its stronger link is definitely with energy efficiency. Therefore, it was penalised by the softer approach that the European policy has historically had on energy efficiency, as schematised in the diagram hereunder.



However, the latest pieces of the European energy and climate policy, as the Energy System Integration and the Hydrogen strategies or the Fit for 55 package, show a stronger focus on energy efficiency that may favour CHP, as analysed in the report. These policies also show somehow the direction for the evolution of cogeneration. In the future, cogeneration will have to be highly efficient and it will probably have to rely on renewable energy sources, for its performance to be decoupled from the price of fossil fuels and emission allowances. CHP will have to be flexible, to facilitate the integration of larger shares of intermittent renewables in the power sector by decoupling electricity and heat production through thermal storage or other strategies. Finally, it may have to focus on smaller scales, in order to get closer to consumers and be aligned with the decentralised energy paradigm, e.g., in district heating and cooling applications for energy communities.

The report also assesses the potential participation of CHP in different markets (section 2), focusing on the potential barriers that this technology may face. In the electricity market, the participation of CHP units has historically been limited to the day-ahead and the intraday market segments and, also in this case, such participation was often affected by support schemes. The largest potential for new market revenues is probably in the very-short-term segment of the market (balancing and flexibility markets) and in resource adequacy mechanisms, which are becoming ubiquitous in the European Union. The main barriers for this participation are related to minimum bid sizes and to the possible inability of the CHP unit to decouple the electricity from the thermal energy production.

CHP is also active the market for heat, usually in the framework of district heating and cooling networks. The report assesses the regulation of heating networks, highlighting the broad heterogeneity of approaches that can be found in Europe, ranging from fully deregulated sectors with

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minimum regulatory oversight to strict regulations for heating networks that are mostly publicly owned. The report focuses in particular on tariff design and third-party access.

Cogeneration facilities may also participate in other markets, beyond electricity and heat, and access to other sources of remuneration. The report assesses the participation of CHP in the EU Emission Trading Scheme, the guarantees of origin for electricity, and the hydrogen market (where CHP can act both as a consumer and a producer of low-carbon or renewable hydrogen). The report also provides a classification of different support schemes that have been used in Europe to incentivise cogeneration, in terms of target and type of support and risk-management strategies. Also in this case, very different trends can be found, with some countries, as the United Kingdom, which may phase out incentives to non-renewable CHP, since its higher efficiency does not offset its carbon footprint compared to its competitors, as the electricity generation mix integrates larger shares of renewables.

Finally, the report presents four case studies on the regulatory environment for CHP (section 3): Sweden, Spain, Germany, and Italy. Each case study assesses the current situation of the CHP industry in the country, the main regulation that drove the deployment of cogeneration, the way in which CHP participate in the electricity market, the regulation of heating network, and the prospective for the sector. The above-mentioned heterogeneity can be found also in the four case studies, although none of the CHP sectors analysed shows a clear growing trend. In some cases, investors are facing large uncertainties and are waiting for further regulatory developments, while in other contexts, as in Spain, the CHP industry is expected to rapidly decrease and only little new capacity will be installed in the coming years.

Motivation of the report within the Bio-FlexGen project

This internal report has been developed in the framework of work package 3, task 3.5, of the Bio-FlexGen project. All the information collected in this report shall be used as an input for other tasks and work packages of the project, especially as regards the potential revenue streams and markets for the technology to be developed in the framework of this project (task 3.2), the definition of potential use cases (task 3.4), and the identification of a proper business model for this technology and of the barriers it may have to face (tasks 4.1, 4.2, and 4.5).

Disclaimer

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Acronyms

aFRR	Automatic Frequency Restoration Reserves
BAT	Best Available Techniques
CACM	Capacity Allocation and Congestion Management
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CLEF	Carbon Leakage Exposure Factor
CSCF	Cross-Sectoral Correction Factor
CHP	Combined Heat and Power
CRM	Capacity Remuneration Mechanism
DH	District Heating
EC	European Commission
ECU	European Currency Unit
EED	Energy Efficiency Directive
EU	European Union
EU ETS	European Union Emission Trading Scheme
FCR	Frequency Containment Reserves
GHG	Greenhouse Gases
HAL	Historic Activity Level
IED	Industrial Emission Directive
JRC	Joint Research Centre
mFRR	Manual Frequency Restoration Reserves
NECP	National Energy and Climate Plans
PES	Primary Energy Savings

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RED	Renewable Energy Directive
RR	Replacement Reserves
RWC	Renewable-Waste-Cogeneration

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1 European legislation on CHP

Combined Heat and Power (CHP), or cogeneration, is a technology that allows the joint production of electricity and thermal energy, thus significantly improving the efficiency of the process. Nonetheless, CHP is a "label" that encompasses many technological solutions, energy management approaches and final uses (Westner and Madlener, 2011; Rezaie and Rosen, 2012). Cogeneration can be based on a topping cycle (electricity is produced first and the exhaust gases are used to generate heat) or on a bottoming cycle (thermal energy is produced first and the residual steam is used to generate electricity). The CHP plant may be operated to follow either the electrical load or the thermal load, so that one energy vector becomes the by-product of the other. Finally, CHP may serve very different final uses, which are usually divided in two broad categories, i.e., district heating/cooling and industrial processes.

Furthermore, cogeneration is a technological solution that heavily depends on local conditions (Sokołowski, 2020). The local climate is a driver for the thermal energy demand. Industrial development or availability of heating networks influence the potential final uses of CHP. The availability of local energy resources (e.g., biomass, geothermal energy, or waste) affects the cogeneration technology and its business model. Finally, local authorities may affect the development of CHP in their region through different authorisation processes and rules.

The broad heterogeneity of combined heat and power and its dependence on the local conditions are two factors that significantly affect the regulatory environment on cogeneration. In fact, it is not easy to find policies able to promote the whole spectrum of technological solutions and final uses included in the "CHP label". On the other hand, the reliance on local conditions fostered regulatory approaches that left most decisions to local or national authorities, resulting in very different outcomes within the European geography.

This first section of the report analyses the main elements of the European policy affecting the development of combined heat and power. First, it presents some basic figures on the role of CHP in today's European energy systems, in terms of share of CHP in the power generation mix or the application in different final uses. Secondly, it analyses current and past EU policy on cogeneration, focusing on the main pieces of legislation issued in the last two decades. Finally, it assesses the role of CHP in the most recent strategies and reform proposals produced by the European Commission regarding climate and energy.

1.1 Basic figures on CHP development in the European Union

Cogeneration is anything but a new technology. The first commercial power plant, built by Edison in Pearl Street, New York, in 1882 was a CHP plant (Hickey, 2016) and produced electricity and steam for local manufacturers and nearby buildings. The combined production of heat and power was very common in the first stage of development of power sectors worldwide, but its share dropped when power systems began to grow larger. In the last decades, the interest in CHP was commonly prompted by oil crises, when the rise in the price of oil in international markets drove initiatives on energy efficiency. However, the position of CHP during such crises was ambivalent since most of cogeneration has historically been operated with fossil fuels, so they were also subject to the price increase.

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In the European Union, large differences in the development of CHP can be found in Member States, reflecting the dependence on local conditions mentioned above. Considering the European Union as a whole, the cogeneration sector is in a phase of stagnation. Figure 1 shows the electricity generation from CHP units and their share in the total electricity generation. In the last two decades, the share of CHP in electricity generation has oscillated between 10% and 12%, without any identifiable trend.

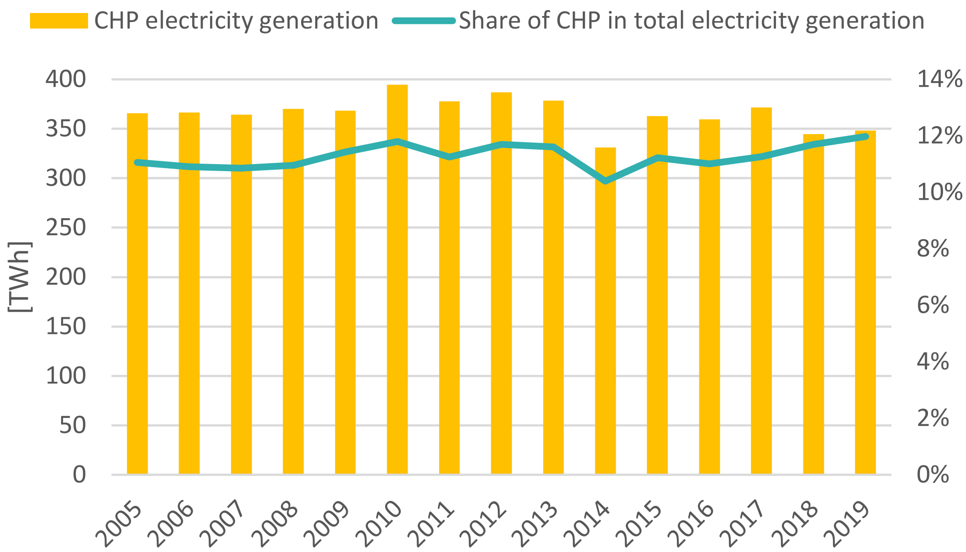

Figure 1. Electricity generation from CHP in the European Union and its share in the total electricity production; data from Eurostat (2021)

Figure 2 presents the evolution of the primary energy source of European CHP power plants in the last ten years. Historically, natural gas has been the main fuel driving cogeneration units. However, the chart shows a clear growing trend for renewable-driven CHP, mainly biomass, which almost doubled its share, from 13% in 2009 to 24% in 2019. Relying on renewables allows CHP to decouple its variable costs from the price of fossil fuels, thus offering stronger benefits during price crises as the one the European Union is experiencing in 2021/2022.

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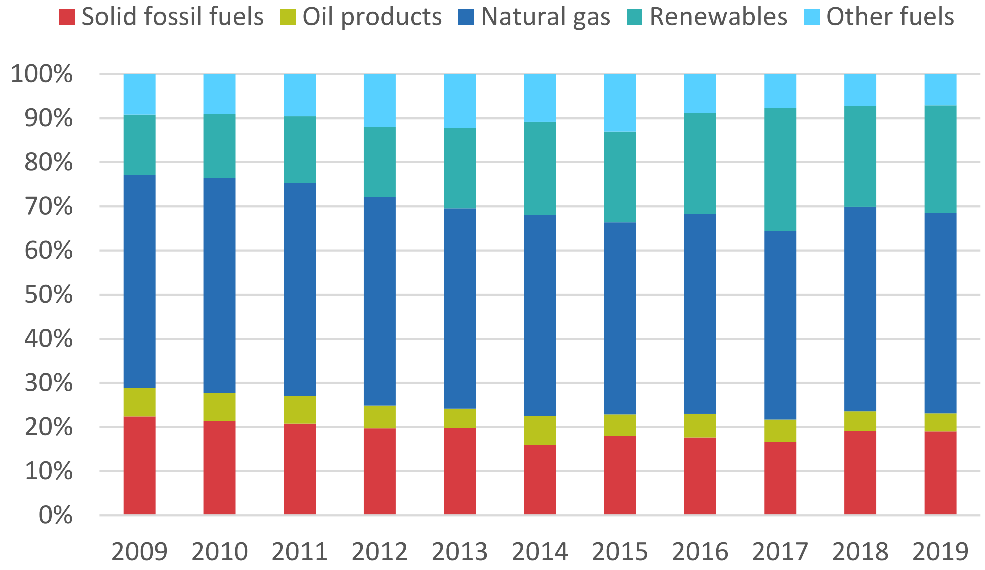

Figure 2. Fuel mix of CHP units in the European Union; data from Eurostat (2021)

As regards the sector or the final use where CHP is applied, historically, the European cogeneration sector has always been split between industrial uses and residential district heating. Figure 3 shows the breakdown of European CHP by sector. The technology most commonly used for the combined production of heat and power is a CCGT with heat recovery (utility-scale CHP normally coupled to district heating), as shown in Figure 4.

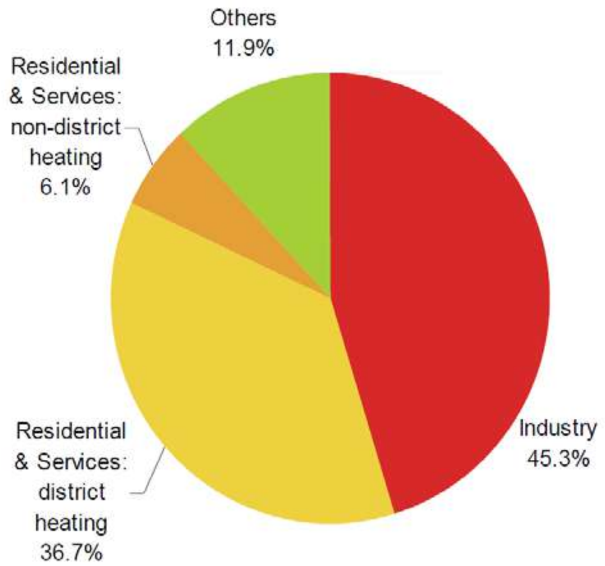

Figure 3. Breakdown of European CHP by sector; capture from EC (2014)

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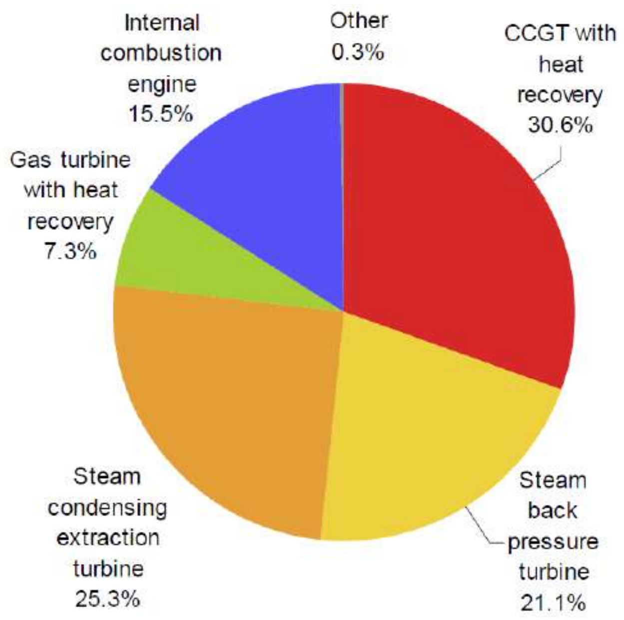

Figure 4. Breakdown of European CHP by technology for electricity production; capture from EC (2014)

Figure 5 presents the electricity generated by CHP units in European Member States in 2019. Germany has by far the largest CHP capacity in Europe, followed by countries from both Northern (The Netherlands, Poland, or Finland) and Southern Europe (Italy and Spain).

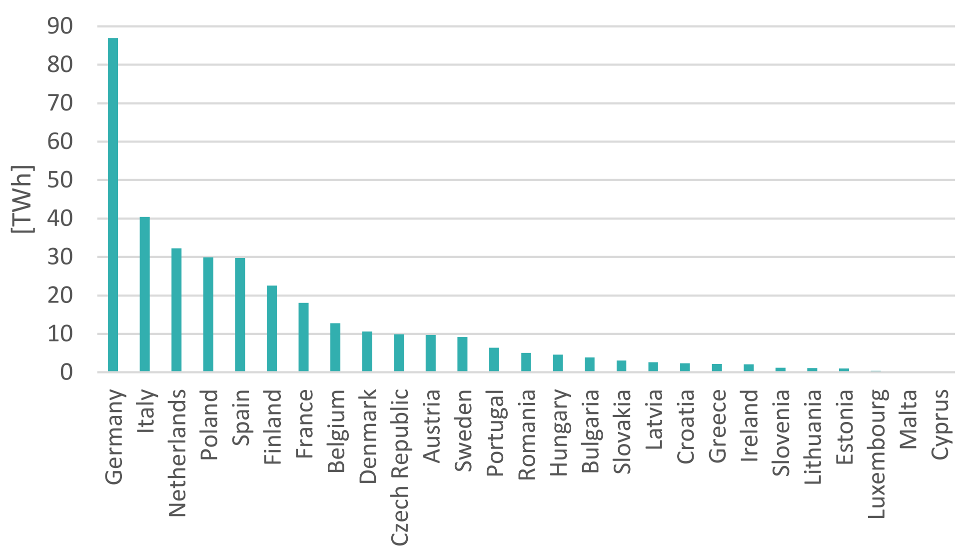

Figure 5. CHP electricity generation in 2019 in European Member States; data from Eurostat (2021)

However, when analysing the share of CHP in total electricity generation for each Member State (Figure 6), it is easier to identify a trend, with higher shares in those Member States where the demand for heat is higher due to climatological reasons. Nonetheless, the chart shows also that climate is not the only driver for CHP development. For instance, France, whose power sector is dominated by

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nuclear power plants which provide cheaper electricity than in the rest of Europe, presents a very low share of CHP, even if its climate is colder than the one of Southern European countries.

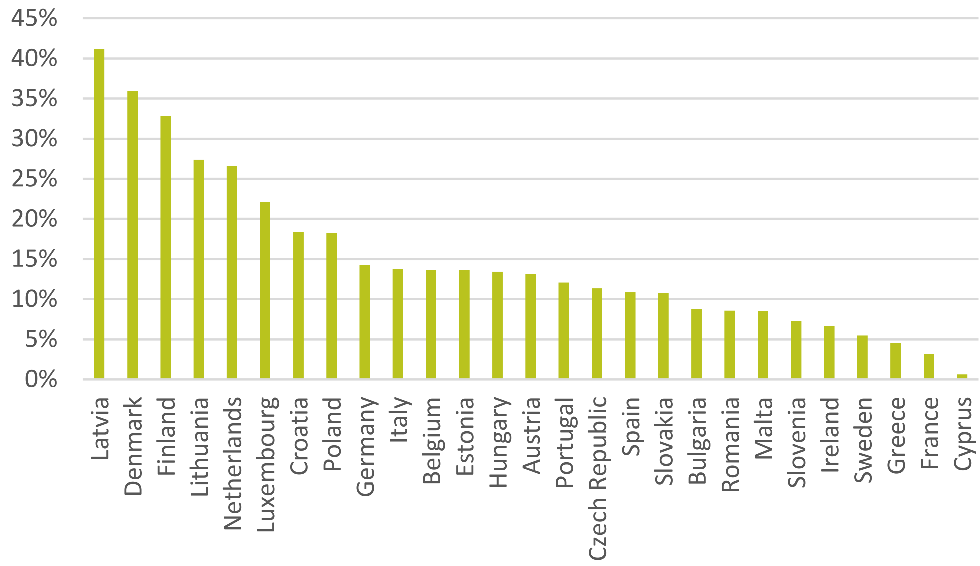

Figure 6. CHP share in total electricity generation in 2019 in European Member States; data from Eurostat (2021)

After this initial characterisation of CHP in the European Union, the next subsection analyses the main pieces of European legislation that had a significant and direct influence on the development of the cogeneration sector.

1.2 Historical perspective on EU policy regarding CHP[1]

Combined heat and power, especially when driven by renewable fuels, can contribute greatly to the three main climate and energy policy objectives of the European Union (energy efficiency, renewable energy, and GHG emission reductions). The European Commission recognised this potential contribution and tried to promote the deployment of CHP since the 1980s. Due to its versatile use cases and its potential to contribute to the achievement of different environmental objectives, cogeneration was affected by many pieces of legislation, ranging from energy efficiency and renewable development to market liberalisation. Figure 7 shows the main EU legislation relevant for CHP, divided among the energy packages that were released in the last two decades.

[1] This subsection draws on Sokołowski (2020), who analysed in detail the European law on CHP.

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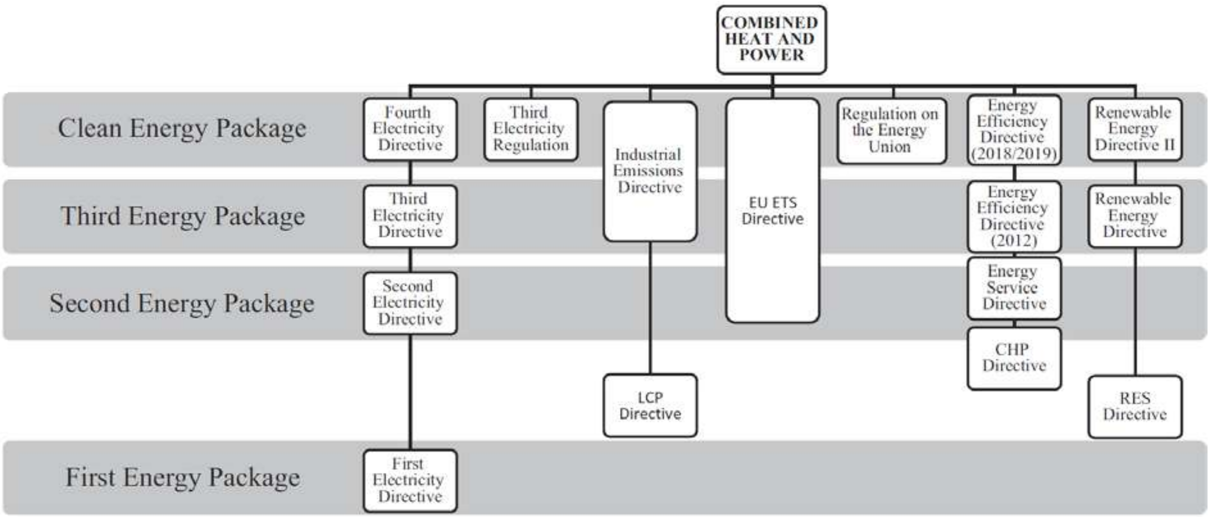

Figure 7. Main European legislation on CHP; capture from Sokołowski (2020)

Other policies can also be relevant for CHP and the technology being proposed in the framework of this project. The rest of this subsection describes the main elements of the EU legislation and their impact on the deployment of CHP.

1.2.1 Early policies

The initial interest towards cogeneration and its potential for improving energy efficiency was driven, in Europe, as well as in other regions, by the oil crises in the 1970s. The latter prompted several EU policies on the rational usage of energy, with indicative objectives for energy savings of 15% for 1985 (European Council, 1974) and for improvement of the efficiency of energy demand of 20% for 1995 (European Council, 1986)[2]. In these policies, CHP was considered as one of the means to achieve a more rational usage of energy. Some principal decisions taken back then have characterised EU policy on cogeneration over the last decades. First, CHP driven by fossil fuels was exposed to price shocks in the oil market, therefore, in order to contribute to the EU objectives, cogeneration had to reduce its dependence on fossil fuels, for instance, through waste-to-energy technologies. Secondly, it was recognised that CHP, as already mentioned in this section, was heavily influenced by the local conditions. This resulted in a legislative approach based on interventions at the local level more than at the European level.

The first framework for supporting combined heat and power had to wait until 1988, when cogeneration was grouped together with renewables and waste energy as RWC (Renewable-Waste-Cogeneration) auto-producers. Recommendation 88/611/EEC of the European Council (1988) required Member States to establish the conditions to foster the sale of electricity from RWC auto-producers to utilities. The remuneration for the electricity injected in the network by these resources had to be determined as transparently as possible to promote the profitability of these technologies. Some

[2] The 1974 15% energy-saving target was set with respect to the level of energy consumption in 1985 estimated through projections by European institutions. The 1986 20% energy-efficiency target was set as an improvement of the efficiency of energy demand, measured as the ratio of final energy demand and the gross national product, to be achieved between 1986 and 1995.

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European countries started promoting CHP under this framework (especially Denmark, Ireland, Italy, or the Netherlands, according to Sokołowski, 2020).

In order to achieve the 20% energy saving target for 1995, The European Council introduced several programmes that provided financial support to projects of different levels of implementation: the Joule Programme, granted with 122 million ECU[3]; the Thermie Programme, with 350 million ECU; and the Save Programme, with 35 million ECU. Some of this financing went to cogeneration projects as enablers of energy efficiency.

1.2.2 CHP Strategy

In a changing legal environment (the Maastricht Treaty entered into force in 1992 and initiated the energy sector liberalisation process, see subsection 1.2.5), the European Commission issued a Strategy on CHP (Communication COM (97) 514 final). Its objective was to define a more comprehensive framework for cogeneration. The Strategy highlighted some of the main barriers that were hindering the deployment of CHP in Europe, dividing them between economic (low remuneration for cogenerated electricity, high fuel prices, or uncertainty regarding the evolution of the prices of inputs and outputs) and regulatory/institutional barriers (time-consuming or expensive licensing procedures, or lack of transparency in the process for connecting the CHP unit to the network). The Strategy also identified that vertical-integrated monopolies were hampering the development of cogeneration through rules and procedures that made this technological option unattractive to investors. This situation was to be solved through market liberalisation.

The Strategy on CHP reinforced the idea that a decentralised approach was better suited to support cogeneration in Europe, leaving the promotion of combined heat and power to the Member States, a feature that would influence the entire EU legislation on this sector. Finally, the Strategy proposed the definition of a very ambitious target: to double the 9% share of CHP in electricity generation in Europe by 2010. As the charts in section 1.1 show, this 18% target was never achieved.

1.2.3 CHP Directive

The Directive 2004/8/EC, also known as the CHP Directive, as the CHP Strategy, was motivated by barriers that were slowing the necessary growth of cogeneration in Europe. In 2004, these barriers were divided into four categories: high fuel prices, access to the electricity network and market, higher costs and lower operating hours of CHP compared to competing technology options. During the elaboration of the Directive, the Commission stressed once again the need for a large local heat demand, since thermal energy cannot be transported over large distances. It defined three areas where CHP could be efficiently deployed: industrial applications, district heating, and agricultural applications. The beneficial role of the liberalisation process was downsized since it could provide new opportunities to CHP and reduce the power of incumbents, but it also forced cogeneration to compete in the market with technologies that may have a more predictable or more favourable economic outcome.

The CHP Directive introduced the definition of high-efficiency cogeneration (CHP with primary energy savings compared to the separate production of electricity and heat, as defined in Annex III of the

[3] European Currency Unit, predecessor of the euro (EUR).

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Directive, higher than 10%). Figure 8 shows the percentage of CHP, for each European country, that can be classified as high-efficiency cogeneration, a technological solution which is predominant in Europe. For the promotion of cogeneration and high-efficiency cogeneration, the Directive considered a catalogue of tools to be implemented by the Member States: support schemes, measures to facilitate the access to the grid, guarantees of origin, and studies on the national potential for high-efficiency cogeneration.

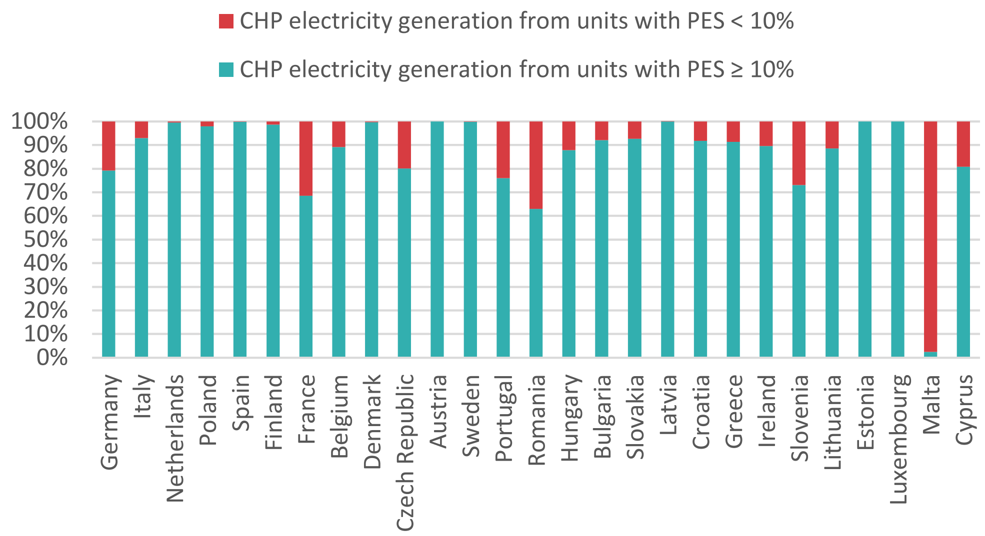

Figure 8. Share of high-efficiency cogeneration in European Member States; data from Eurostat (2021)

1.2.3.1 Support schemes

The Directive recognised that some financial support was required to foster the development of the cogeneration sector and to recognise the value of its higher energy efficiency. Member States were called to ensure an appropriate support to CHP. No specific requirement regarding the design of the support scheme was defined. However, the latter had to be compatible with the internal energy market.

This approach resulted in a patchwork of very different schemes at the national level, with Member States not only selecting different designs for their support schemes, but also identifying different categories of CHP plants eligible for financial aid, in terms of fuel type or unit size. The most common support schemes were some form of capital grants for the installation of CHP plants and feed-in tariffs, premia, or any other type of guaranteed purchase price for the electricity generated by cogeneration. Another type of operational support was the creation of a certificate scheme, which provided certificates to CHP project developers, who could sell them to some agents with the obligation to purchase them to achieve a certain target (e.g., a certain percentage of electricity supplied coming from high-efficiency CHP), thus creating a certificate market on a national level. Finally, a broad range of fiscal mechanisms was implemented in several Member States, like tax deductions or accelerated depreciation. Table i shows the support schemes implemented in each European Member State with some Member State introducing more than one mechanism.

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Table i. Support schemes for cogeneration in Europe; capture from Sokołowski (2020)

Member States	support measures					
	feed-in tariff/guaranteed purchase price type of support	certificate scheme	energy tax exemption	business tax exemption	accelerated fiscal allowance for investment	capital grants
	operational	operational	operational	operational	investment	investment
	indicate range of value					
	15–80 EUR per MWh	~ 40 EUR per MWh	2–12 EUR per MWh (electricity produced)	minor	5%–10% of investment costs	10%–50% of investment
Austria						x
Belgium		x			x	x
Bulgaria	x					
Cyprus	x					x
Czech Republic	x					x
Denmark	x			x		x
Estonia	x					
Finland			x			x
France	x		x	x	x	
Germany	x		x			x
Greece	x					x
Hungary	x					
Ireland					x	x
Italy		x*	x			x
Latvia	x					x
Lithuania	x					x
Luxembourg	x					x
Malta						
Netherlands			x		x	x
Poland		x				x
Portugal	x					x
Romania						
Slovakia	x					x
Slovenia	x		x			x
Spain	x					x
Sweden			x			
UK	x		x	x	x	x

* CHP qualified as eligible for certificate schemes enhancing energy efficiency (white certificates).

1.2.3.2 Guarantees of origin

Guarantees of origin are a tracking scheme that grants a label to certain energy products. Such a label is supposed to improve the transparency in the energy market and the knowledge of energy consumers; it is also expected to provide the labelled product with an economic advantage in the market itself. The CHP Directive required Member States to introduce a scheme of guarantees of origin for the electricity produced by high-efficiency cogeneration. Each Member State introduced its own scheme, identifying the entity in charge for its management, commonly the national regulatory authority. According to Sokołowski (2020), despite the adoption of guarantees of origin by all Member States, these schemes have not been fully operational in half of them.

1.2.3.3 Access to the grid

In terms of access to the grid, the CHP Directive extended to high-efficiency cogeneration the provisions already introduced for renewable energy sources (through Directives 2001/77/EC and 2003/54/EC) in terms of priority access and priority dispatch. As in the case of renewables, the boundary between these two concepts was blurred, and several Member States interpreted them as synonyms (EWEA, 2014). According to the Commission (Staff Working Document

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COM(2013) 938 final), twelve Member States had introduced priority grid access, while six had some kind of assisted access. Priority access was linked with the guarantees of origin scheme in four Member States.

1.2.3.4 National potentials for high-efficiency cogeneration

The CHP Directive also required Member States to develop assessments on the national potentials for high-efficiency cogeneration, with the objective of identifying all heating and cooling demands that high-efficiency CHP could supply. The Directive also defined a list of contents that these assessments had to have. However, as in other aspects of the CHP Directive, this approach resulted in a broad heterogeneity of the analyses presented by Member States and very different outcomes. Figure 9 compares the overall potentials for cogeneration identified by some Member States for 2020 (Staff Working Document COM(2013) 938 final) with the actual energy produced by CHP in each of these Member State in 2019 (Eurostat, 2021).

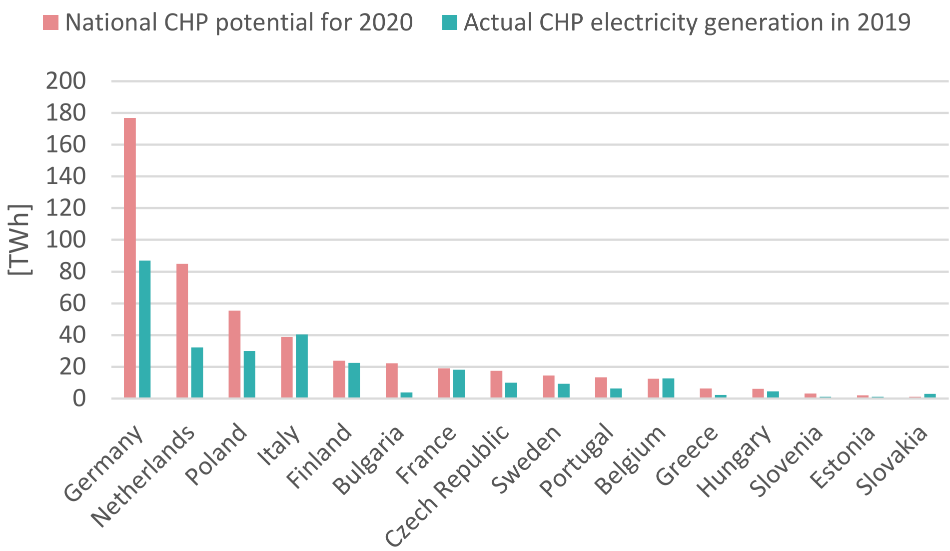

Figure 9. National CHP potentials for 2020 vs. actual CHP electricity generation in 2019; own elaboration based on data from EC (2014) and Eurostat (2021)

The results shown in Figure 9 could be explained by differences in the effort for CHP development. However, they reflect especially the different assumptions that national assessments were based on. Furthermore, it is important to understand that these assessments did not result in any associated obligation by the Member States to realise the identified potentials.

1.2.3.5 Outcomes of the CHP Directive

The Commission and various independent reviews recognised that the impact of the CHP Directive was small if compared with its ambitions. Cogeneration only saw its installed capacity growing from 95 GW in 2004 to 100 GW in 2008. According to Sokołowski (2020), the main problem was related with the soft approach of the Directive, without binding requirements as those established for other technologies, and with a decentralisation of the legislative activity towards Member States resulted in a patchwork of different regulations, which increased the perceived risk for investors.

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1.2.4 Energy Efficiency Directive

The CHP Directive was repealed, in 2012, by Directive 2012/27/EU, also known as the Energy Efficiency Directive, or EED. The main driver of the new legislation was the expected failure to achieve the 20% energy efficiency target for 2020. According to the Commission (Communication COM(2011) 370 final), Member States were on track to achieve a 9% target set for 2016, but the 20% was out of reach. During the draft of the Energy Efficiency Directive, the Commission recognised the flaws of the CHP Directive and debated on whether the latter had to be removed completely, leaving all initiatives to Member States, or the sector had to be included in the EED, as one of the main potential providers of energy efficiency. This second alternative was eventually implemented.

Although the EED repealed the CHP Directive, it did not introduce a change in the direction of the European regulation for the sector. Most of the measures and approaches from the CHP Directive were maintained or slightly modified (as for the guarantees of origin from high-efficiency cogeneration). The main elements of the Energy Efficiency Directive regarding CHP can be grouped as promotion and simplification of administrative procedures, guaranteed access and priority dispatch, and comprehensive assessments of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling.

As regards promotion and simplification, the EED calls for stronger support to cogeneration with an installed capacity lower than 20 MW to encourage distributed energy generation. The Directive also required network operators to facilitate connections of high-efficiency cogeneration, providing project developers with information regarding connection costs and maintaining the overall process to become connected below 24 months.

The EED also maintained the clauses regarding guaranteed access to the grid and priority dispatch for high-efficiency cogeneration. However, the same text also specifies that when providing priority dispatch to high-efficiency cogeneration, Member States may set rankings between renewable energy and high-efficiency cogeneration and should ensure that priority dispatch for renewable is not hampered by the inclusion of CHP.

Finally, the Energy Efficiency Directive requires Member States to develop a comprehensive assessment of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling in their national territories every five years. When such an assessment identifies interventions in these sectors for which the benefits exceed the costs, the Member State should take measures for such investments to happen. According to several experts, the national assessments notified by Member States as per the EED presented a clear preponderance of district heating and cooling over combined heat and power (Sokołowski, 2020), as actually indicated by the Annex VIII of the Directive, which provided some sort of template for the assessments.

Beyond this country-wide assessment, the Directive also requires that ad-hoc assessments are carried out when i) a new power plant beyond 20 MW is planned, ii) an existing power plant beyond 20 MW is substantially refurbished, iii) an industrial facility with a heat demand higher than 20 MW is planned or refurbished, or iv) a new district heating and cooling network is planned, in order to estimate the

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costs and benefits of the installation of high-efficiency cogeneration[4].As highlighted by some authors (Colmenar-Santos et al., 2015), this does not introduce a legal obligation to install those facilities that are economic-efficient.

The EED received similar criticisms as the CHP Directive (too-soft approach, lack of legally binding targets) and was considered insufficient to promote a faster deployment of cogeneration in Europe (COGEN, 2012; Sokołowski, 2020).

1.2.5 The three Energy Packages

Starting from 1996, the first (Directive 96/92/EC), the second (Directive 2003/54/EC), and the third energy package (Directive 2009/72/EC) were issued by the European Commission to liberalise European energy sectors and create the Internal Energy Market. The liberalisation process did not have a specific focus on combined heat and power, but it did have an impact on the technology.

Especially when drafting the first energy package, the liberalisation of the energy sector and the creation of the electricity market were seen as something positive for emerging technologies and especially for small-scale local units, since it would have allowed them to compete with incumbents, opening new market spaces for these technologies to thrive.

This point of view was challenged when drafting the second energy package. European institutions recognised that direct competition between clean energy technologies, including cogeneration, and conventional resources may have hindered the deployment of new technologies and the decarbonisation of the energy system. This was due to the presence of externalities, like environmental costs, that were not being properly internalised in the energy market, providing a competitive advantage to conventional technologies. Cogeneration was recognised as a technology in need of specific support. However, as already discussed for the CHP Directive, the Commission deemed that such support had to be designed at the Member State level.

The three energy packages were therefore neutral to the development of combined heat and power and had the same soft approach that was already described for the CHP Directive, with a strong focus on national policies.

1.2.6 Clean Energy Package

In 2019, the Clean Energy Package brought the liberalisation process and energy and climate policy together. One of the main novelties with a potential impact on CHP was the introduction of the principle known as “energy efficiency first”, which has been mentioned in all subsequent visions, strategies or legislations. The Clean Energy Package also amended the Energy Efficiency Directive based on this principle. However, no significant change in the regulatory framework applicable to cogeneration can be highlighted.

One of the main elements of the Clean Energy Package was the obligation, under the so-called Regulation of the Energy Union (Regulation (EU) 2018/1999), for Member States to develop and deliver integrated national energy and climate plans (or NECPs). These plans are long-term planning tools for the energy sector; the first period that has been covered by NECPs is 2021-2030. The regulation

[4] Several exemptions were considered, as, for instance, for nuclear power plants.

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outlined a detailed structure of contents for these plans. Energy and climate plans have to include clear commitments on energy efficiency and measures to achieve them. One of the areas that should be assessed in national plans, according to Regulation (EU) 2018/1999, is the current potential for the application of high-efficiency cogeneration and efficient district heating and cooling. Beyond this specific assessment, the energy-efficiency-first principle should require Member States to consider any pro-efficiency measure before any other possible action on the energy sector is considered (Sokołowski, 2020). If applied properly, this may create a very significant space for CHP.

However, the Clean Energy Package also contained elements that reduced the regulatory support to cogeneration with respect to the previous environment. The so-called Fourth Electricity Directive (Directive (EU) 2019/944) repealed some measures to support cogeneration technology, such as their priority dispatch. CHP units are now required to operate under the same market rules as the rest of the electricity generation fleet, subject to a merit-order dispatch. This also has consequences in terms of balance responsibility, prompting CHP operators to fulfil dispatch commitments. Such an approach, that mimics a similar strategy for intermittent renewables, had the objective to foster flexibility-enhancing strategies in cogeneration facilities, as for instance the installation of thermal storage. Only small-scale CHP, with an installed capacity lower than 400 kW, may still be subject to priority dispatch, although there is no requirement, and the decision is left to Member States. Although many CHP installations can improve their flexibility in response to these regulatory reforms, the European Association for the Promotion of Cogeneration, COGEN Europe, remarked how achieving this flexibility may come at the expense of the site efficiency and industrial productivity (Sokołowski, 2020).

1.2.7 Industrial Emission Directive

According to the Industrial Emissions Directive, all industrial installations within the EU running operations with potential harm to the environment through emissions to air and water must hold an environmental permit issued by the competent authority within each Member State. The European Union has a long track record of legislation that sets rules and limits the pollution caused by industrial facilities. However, in 2010 the Industrial Emission Directive, or IED, was introduced to homogenise various previous directives that address the environmental impact of industrial activities (Directive 2010/75/EU). According to the European Commission, the IED is based on several pillars, particularly an integrated approach, best available techniques (BAT), flexibility, inspections, and public participation. Each of these pillars aims to foster the modernisation of existing industrial facilities and ensure through the environmental permits that new installations fulfil minimum criteria for their environmental impact. By an integrated approach the full picture of the environmental impact of a plant shall be considered, including, among others air, water, noise emission and waste. Comparing plant performance to BAT shall ensure comparability to reference values. However, Member States are granted flexibility to temporarily diverge from these reference values if compliance to BAT reference values would require disproportionate costs due to local conditions. Regular inspections and public participation in the decision-making and evaluation process shall ensure stringent monitoring.

Under the IED, the permits for industrial installations shall hold instructions as to how the activities are to be evaluated based on their direct emissions to air and water and aspects such as noise level, land use, and raw material handling. Concerning air emissions, the Directive focuses on all non-greenhouse emissions, among others sulphur, nitrogen compounds, carbon monoxide and dust emissions, but not carbon dioxide (CO_2). Therefore, the Directive is critical for energy carriers causing these emissions,

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such as direct biomass combustion (Wielgosiński et al., 2017). The IED encourages efficient energy use and emission reductions by benchmarking existing and new installations against best available technologies (BAT). Multiple BAT reference documents (BREF) by the European Commission referenced within the IED refer to CHP as the best available technology option, thereby indirectly promoting its implementation.[5] The Directive itself is technology-neutral. However, BAT benchmarks are set based on specific technologies for each industry. Jointly with the Directive on emissions of certain pollutants (Directive (EU) 2015/2193), such as SO_2, NO_x and dust, the IED can restrict some thermal use cases for biomass. The IED leaves some flexibility to Member States regarding the translation of the Directive and emission limits for specific national applications. The Commission's evaluation of the IED published in 2020 (SWD/2020/0181 final) points out various shortcomings about the effectiveness of the Directive. Among others, Member States tend to apply the least stringent emission values set for BAT technology in the national permitting process[6].

1.2.8 Relevant legislation for biomass use in CHP

The operation of CHP with bio-based fuels combines a highly efficient combustion technology with a sustainable[7] fuel source, maximising the usable energy yield. Sustainable biomass allows for the emission-neutral generation of heat and electricity and has become the second CHP most common fuel in Europe, only behind natural gas. However, in the past, biomass use for CHP has not always been economically viable. Based on historical natural gas prices, biomass used to require a shadow emission allowance price (€/tCO_2eq) to be competitive, exceeding the historically observed market price for the EU ETS allowances (Jåstad et al., 2020). As such, biomass use for CHP is a technology option that has relied on a favourable regulatory framework beyond the EU ETS to compete with fossil-based heat and electricity generation. In the following, we review how relevant European legislation has developed over time to support and foster this technology option within the EU. Based on the historic development of EU legislation, we make a clear differentiation between biofuels and biogas as a direct replacement of liquid and gaseous fossil fuels in CHP installations and the direct use of biomass, covering all relevant Directives since 2001.

In 2001, EU Member States set targets for the share of electricity production from renewable energy sources by 2010. The Directive on the promotion of electricity produced from renewable energy sources in the internal electricity market (Directive 2001/77/EC) listed biomass as one of the renewable energy sources that may contribute towards achieving the targeted quotas. However, neither the legal text defines sustainable biomass nor specifically mentions CHP technology.

Also, the following Directive 2003/30/EC on the promotion of the use of biofuels or other renewable fuels had little relevance for the use of biomass for energetic purposes in stationary installations since

[5] See, for example, the BAT reports for Energy Efficiency (2009, corrected in 2021), Iron and Steel Production (2013) or Cement (2013).

[6] The aforementioned JRC BAT reports define emission ranges for BAT technologies, leaving it to the Member States to define emission limits within these ranges.

[7] In the following, the term "sustainable" biomass is used to refer to biomass from sources that are sustainable in accordance with the definition of the United Nations Brundtland Commission, as "meeting the needs of the present without compromising the ability of future generations to meet their own needs".

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it only addressed biofuel use in the transport sector. As such, scholars evaluating the Directive's impact criticise its limited ability to reduce emissions by not covering sectors with a potentially higher emission reduction potential than road transport, such as electricity generation (Sobrino and Monroy, 2009). While the Directive was of little importance for CHP installations, it should be noted that it included a first attempt to define and promote sustainable biomass use.

The Union's restructuring of the taxation framework of energy production and electricity in 2003 gave Member States more liberty to offer tax rebates to renewable energy sources (Council Directive 2003/96/EC). While this Directive allowed Member States to adopt taxation schemes that could potentially be highly beneficial to biomass use for energetic purposes, it did little to promote biomass for CHPs on a Pan-European level. According to Article 15 (1(d)), it was left up to the Member States to set criteria for "environmentally-friendly" cogeneration use, therefore encouraging different interpretations and definitions for the sustainability of CHP use.

The first Renewable Energy Directive, or RED I (Directive 2009/28/EC), marked an important step towards a harmonised approach toward biomass use across all energetic end-uses by calling for the establishment of sustainability criteria for bioenergy, encompassing both bioliquids and direct biomass use on a European level. However, the Directive only specified recommendations for sustainability criteria of biomass use, biofuels and bioliquids (Article 17(9)), which led to the publication of recommendations for non-binding sustainability criteria regarding biomass for electricity and heating by the European Commission (Communication COM(2010)11 final). A 2015 report for the European Parliament found that implementation was patchy and seemed to favour divergent national sustainability schemes (Bourguignon, 2015). Articles 17(1) and (2) of the Directive call for developing a certification scheme that ensures biofuels and bioliquids comply with sustainability criteria. However, the practical implication of the certification scheme introduced in the following was far from perfect (Gerres et al., 2021). Some certification schemes did not meet the sustainability criteria, but were only excluded posteriori after their application to certify biofuels and bioliquids. Not relevant for CHP per se, future legislation defining the sustainability of biomass use for electricity and heat production might be based on design principles of the certification scheme.

RED I calls for increased use of biomass, thereby favouring CHP technology in combination with biomass use, such as biomass use in district heating and cooling (Article 16(11)). Furthermore, Article 13(6) states that biomass use shall be promoted for those technologies that achieve a conversion efficiency of at least 85% for residential and commercial applications and at least 70% for industrial applications. This formulation favours the use of biomass for efficient boiler technology and CHP, whereas it disincentives direct combustion of biomass. However, its non-binding character left it to the Member States to promote biomass use for these applications. Empiric research about national support schemes for biomass between 2005 and 2015 demonstrates that Member States had very different approaches towards promoting biomass (Banja et al., 2019). About 50% of the measures were directed towards the transport sector, more than 30% to heating and cooling technologies and less than 20% to biomass use for electricity generation, mainly in the form of biomass and biogas plants. 8.2% of all measures were dedicated to biomass use in CHP installations.

In 2018, the recast Renewable Energy Directive, or RED II (Directive (EU) 2018/2001), introduced quantitative requirements to measure the sustainability of biomass use, thereby setting common European criteria for using CHP for electricity and thermal generation. However, Article 29(1) limits

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the scope of application for greenhouse gas saving criteria to those installations with a total rated thermal input equal to or exceeding 20 MW in the case of solid biomass fuels and with a total rated thermal input equal to or exceeding 2 MW in the case of gaseous biomass fuel, which excludes small CHP installations. Member States cannot account their contribution towards meeting national emission reduction targets. As such, the Directive provides little incentive for Member States to promote biomass use for small scale CHP installations at the residential level, leaving out potential sources for emission reductions. However, a resolution of the European Parliament (EP, 2013) explicitly highlighted the role of microgeneration, such as small-scale CHP, for the energy transition and called upon the European Commission and the Member States to publicise them.

Furthermore, efficiency requirements to include their contribution to national emission reduction targets and renewable energy shares exist for CHP installation using biomass and exceeding 50 MW of thermal input (Article 29 (11)). Biomass CHP can contribute to meeting these targets by the Member States if electricity from biomass:

- is produced in installations with a total rated thermal input below 50 MW.
- for installations with a total rated thermal input from 50 to 100 MW, it is produced applying high-efficiency cogeneration technology, or, for electricity-only installations, meeting an energy efficiency level associated with the best available techniques (BAT-AEELs) as defined in EC (2017).
- for installations with a total rated thermal input above 100 MW, it is produced applying high-efficiency cogeneration technology, or, for electricity-only installations, achieving a net-electrical efficiency of at least 36%.

Additionally, Annex V and VI of the RED II provide instructions on how to account for greenhouse gas emission reduction for the use of biomass, its transport distance and biomass production system. As such, the Directive represents an important step to favour the use of locally available biomass in CHP installations. To ensure the competent installation and maintenance of renewable energy technologies, Article 18 introduces a certification scheme for installers, favouring those installations that efficiently reduce emissions, such as high-efficiency bio-based CHP.

1.2.9 Summary

The development of CHP in Europe in the last decades has been stagnating. One of the reasons is the evolution of the regulatory and legislative environment described in the previous subsections. Although European institutions have always recognised the pro-efficiency capabilities of cogeneration, CHP has been considered just as a tool to achieve energy efficiency, not as a target itself. From the CHP Strategy up to the Clean Energy Package, European regulation has historically had a soft approach. It did not provide binding targets and left most of the policy implementation to the national level. The result is a patchwork of different legislations that increased the risk perceived by investors.

The deployment of CHP has also been hampered by a soft approach on energy efficiency in general. Among the three main elements of the European climate and energy policy, energy efficiency, renewables, and reduction of greenhouse gases, the former always received a different treatment, starting from the 20-20-20 policy, which set binding targets for renewables and emissions, but not for energy efficiency (Sokołowski, 2020). CHP is a technology that can contribute to all the above-mentioned elements, but its stronger link is definitely with energy efficiency. Therefore, it was

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penalised by the softer approach that the European policy has historically had on energy efficiency (Figure 10). This is also one of the reasons that may explain the trend towards renewable CHP, which allow project developers to encompass other policy objectives beyond energy efficiency.

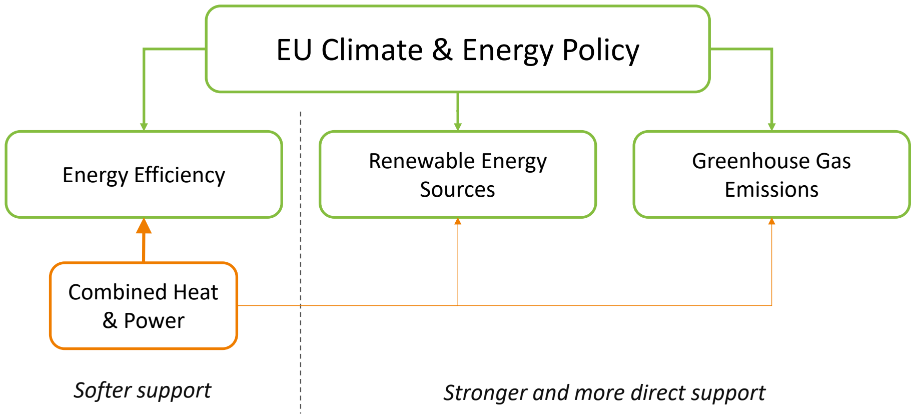

Figure 10. The three elements of the European climate and energy policy

Industrial associations, like COGEN Europe, have called for a so-called RES-CHP parity, asking for equal treatment of renewables and cogeneration in terms of incentives and other facilitating instruments. This has not been the regulatory approach so far, as testified by Sokołowski (2020), where the author states that "there are many indications that cogeneration begins to lag behind RES with every step towards the common energy market; slightly, but noticeably". However, the latest pieces of the European energy and climate policy show a stronger focus on energy efficiency that may favour CHP, as analysed in the following subsection.

In any case, the regulatory trend outlined in this subsection provides some sort of direction for the development of CHP. In the future, cogeneration will have to be highly efficient (as most of the European CHP fleet currently is, as shown in Figure 8). CHP will probably have to rely on renewable energy sources, for its performance to be decoupled from the price of fossil fuels and emission allowances. CHP will have to be flexible, to facilitate the integration of larger shares of intermittent renewables in the power sector by decoupling electricity and heat production through thermal storage or other strategies. Finally, it may have to focus on smaller scales, in order to get closer to consumers and be aligned with the decentralised energy paradigm, e.g., in district heating and cooling applications for energy communities.

1.3 The role of CHP in the most recent energy & climate legislation

While the previous subsection presented the main European law on combined heat and power and biofuels, this subsection focuses on the long-term strategies and visions from the European Commission that could be relevant for cogeneration, as well as the new energy directives currently under discussion.

1.3.1 Energy system integration

In 2020, the European Commission published some long-term strategies that are supposed to drive the so-called European Green Deal in the energy sector. One of the strategies focused on energy system integration (EC, 2020b), which refers to the planning and operating of the energy system as a

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whole, across multiple energy carriers, infrastructures, and consumption sectors, as shown graphically in Figure 11. The integration of different energy sectors, also referred to as sector coupling, is both a necessity for the future decarbonised energy system, but also a great opportunity for delivering low-carbon, reliable and resource-efficient energy services at the least possible cost for society.

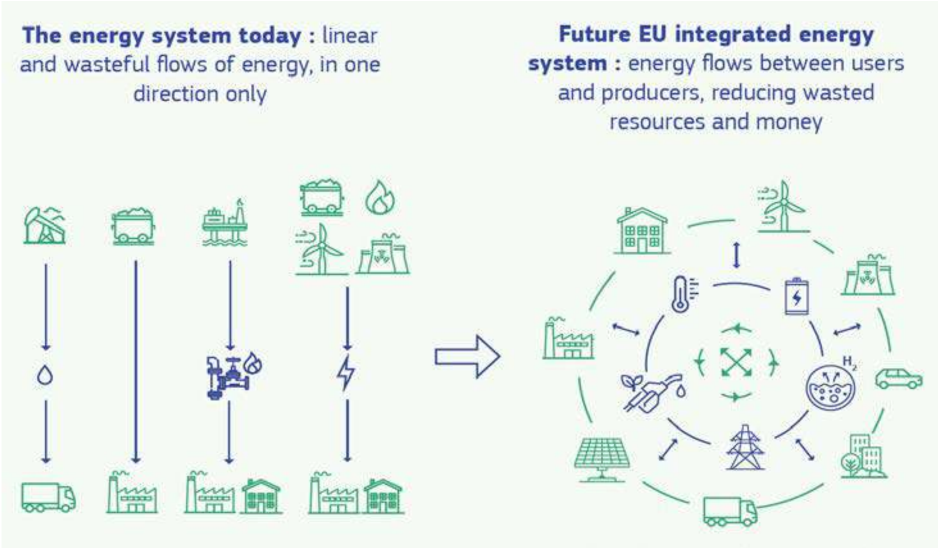

Figure 11. The evolution towards an integrated energy system; capture from EC (2020b)

Combined heat and power has always been at the interface of different energy sectors, providing services through different energy carriers and coupling the power sector with the building or the industrial sector. Therefore, it could benefit from a European policy that fosters energy system integration. Its value is recognised by the strategy, which highlights the advantages of a more circular energy system, with energy efficiency at its core, in which unavoidable waste streams are reused for other energy purposes, and synergies are exploited across all sectors.

Another key element of the energy system integration strategy is the use of low-carbon fuels, including hydrogen, for end-use applications where direct heating or electrification are not feasible, not efficient or have higher costs. This could also be relevant for the technology developed in the framework of this project, which can have hydrogen both as an input and as an output, as assessed also in the following subsection.

1.3.2 Hydrogen strategy

Always in 2020, the European Commission also published a specific strategy on hydrogen (EC, 2020c). The strategy identifies clean hydrogen as an investment priority for Europe, one that could boost economic growth and energy resilience. The focus is on renewable hydrogen, i.e., hydrogen produced through the electrolysis of water (in an electrolyser, powered by electricity), with the electricity stemming from renewable sources. As shown graphically in Figure 12, the strategy sets some indicative targets: 6 GW of electrolysers are expected to be installed by 2024 and scaled up to 40 GW by 2030.

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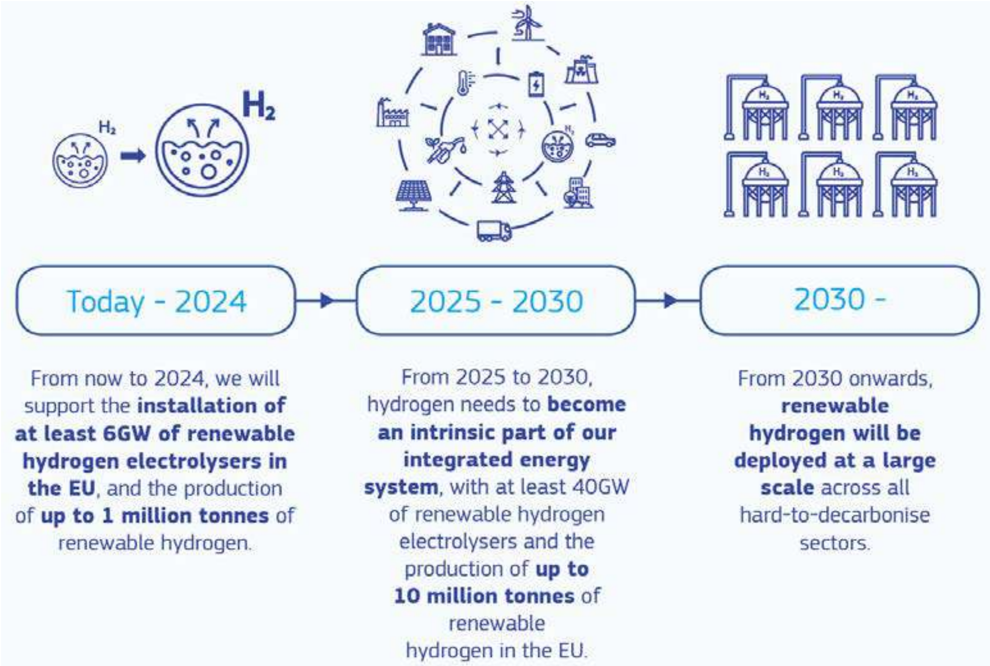

Figure 12. The evolution of the European hydrogen sector; capture from EC (2020c)

The strong focus on renewable hydrogen was promoted by several Member States, especially those endowed with larger amounts of renewable energy sources for electricity. However, it has also been criticised by some experts, since it leaves behind low-carbon hydrogen, produced from natural gas with carbon capture and storage, a technological alternative which may play an important role in the medium term (Barnes and Yafimava, 2020).

The technology being developed in the framework of this research project can use hydrogen as a feedstock for fast-start capability, but it can also support the production of renewable hydrogen, either through a process of water electrolysis driven by the electricity generated in the CHP topping cycle, or directly through the gasification of biomass and catalytic steam reforming. The technology will benefit from a regulatory framework that fosters the hydrogen sector, promoting both the production and the demand of clean hydrogen in order to create a liquid market for this energy vector. Also the strong focus on renewable hydrogen can be beneficial for this technology, since both hydrogen production modes rely on renewable energy sources (see also subsection 1.3.3).

Finally, it must be highlighted that these strategies do not contain any binding target or any specific implementation measures. Their impact on the energy sector will stem from new and revised legislation that they will inspire, starting from the "Fit for 55" package currently under design, analysed in the following subsection.

1.3.3 Fit for 55

The aftermath of the 2015 Paris Agreement has seen a clear shift in EU policymaking. The European Union manifested its long-term vision to become a climate-neutrality economy by 2050. First laid out in the Commission's "Clean Planet for all" vision (Communication COM(2018) 773 final), and followed by the Commission's announcement of the European Green Deal (Communication COM(2019) 640 final), the European Union committed itself to climate neutrality by approving the

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European Climate Law in 2021. Besides the long-term commitment for 2050, the law also sets a mid-term 55% emission reduction target compared to 1990 until 2030 and acknowledges a need for policy actions (Regulation (EU) 2021/1119). Especially, the mid-term target of 55% emission reduction is significantly more ambitious than the previous 40% reduction target that had been in force since 2014. Commonly referred to as the “Fit for 55” package, the ongoing revision of emission, energy, and climate-related legislation may significantly impact the future role of CHP operating with renewable energy resources, such as hydrogen or biomass. In the following, we review the different elements of the package and highlight their relevance for renewable CHP.

In 2021, the European Emission Trading System (EU ETS) entered phase IV, which will lead to an accelerated reduction of the available emission allowance cap until 2030.[8] Sectors currently covered by the EU ETS are subject to new benchmarks for free allowance allocations set to decrease between 0.2% to 1.6% per year, depending on the carbon leakage risks of each industry.[9] As part of the “Fit for 55” package, the EU ETS will be revised and extended to cover maritime shipping and aviation fully and shall be adjusted to accommodate a carbon border adjustment mechanism (CBAM). CHP with renewable energy sources is affected by these changes in two different ways. Free allowances for electricity generation have already been phased out. First of all, higher emission allowances prices due to the allowance scarcity caused by a reduced total emission cap improve the competitiveness of renewable CHP compared to fossil electricity generation. Secondly, reduced free allowance allocation for industrial sectors strengthens the business case for industrial heat generation using renewable CHP. While free allowance allocation muted most of the price signal from the EU ETS for industrial sectors, the commitment towards a lower total emission allowance cap and allocations benchmarks adjusted on an annual basis ensure that the EU ETS price signal impacts both the economics of electricity and heat consumption of industrial consumers. The proposed CBAM can function as a catalyst for the economic feasibility of renewable CHP for industrial applications. In a first step, the current proposal would only include imports of some basic materials like steel, cement, and aluminium into the EU ETS, reducing the carbon leakage risk for these industries and potentially allowing for more aggressive benchmark adjustments during phase IV. The EU ETS revision and introduction of a CBAM would primarily improve the business case for renewable CHP for those sectors that the CBAM covers.

The more ambitious emission reduction target for 2030 in the “Fit for 55” package makes a revision of the renewable energy targets inevitable. The proposed amendments to the Renewable Energy Directive lift the objective for the renewable energy share in the final consumption by 2030 from 32% to 40%. In this context, the proposed amendments further specify those energy sources that are renewable and can contribute to achieving the consumption target. Besides renewable electricity, biomass, and renewable fuels of non-biological origin[10] can help reach the target quota. Latter includes hydrogen produced from renewable sources. However, the proposal defines fuels of non-biological origin as renewable if greenhouse gas savings are at least 70%. CHP can contribute to the renewable target if biomass or renewable fuels are used instead of liquid or solid fossil fuels. If replacing

[8] In 2020 the total cap was 1,816 $MtCO_2e$ (phase III), reduced to 1,572 $MtCO_2e$ in 2021 (phase IV), and set to be reduced by 2.2% (43 million allowances) per year based on the 2008-2021 baseline emissions.

[9] For an overview of EU ETS design elements, see ICAP (2021).

[10] This term is used by the European Union to refer to hydrogen and other non-biological renewable fuels.

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conventional technologies for heat and electricity generation with CHP, the 70% saving target could potentially also be achieved using fossil natural gas. To avoid double accounting, emission reductions of using renewable fuels shall be accounted for on the consumption and not the production side. As such, only the consumer as direct emitter can account emission reductions if using renewable fuels, whereas for the producer of renewable fuels, only direct emissions from its production process can be accounted for.

The Directive frames the different fuel options that can potentially be used for renewable CHP, biomass, and renewable fuels of non-biological origin, very differently. Renewable fuels of non-biological origin shall be promoted for all energetic and non-energetic end uses. However, 50% of all hydrogen demand in the industry shall be met with renewable fuels of non-biological origin by 2030. Additionally, a 2.6% share of renewable fuels of non-biological origin in 2030 is set for the transport sector. As such, there is a clear preference for replacing conventional hydrogen use in industry, predominantly in the fertiliser and refining industry, and its use as a transport fuel. In the case of biomass use, the proposed Directive promotes the cascading principle of biomass use. Biomass should be used in the following order of priorities: 1) wood-based products, 2) extending their service life, 3) re-use, 4) recycling, 5) bio-energy and disposal[11]. Therefore, CHP as a bio-energy provider plays a subordinate role for biomass use. In line with the latest JRC report on woody biomass for energy production, only sustainable feedstock with little market competition for other end uses shall be used (Camia, 2021). Here, CHP is preferred since no support shall be given to biomass use in electricity-only plants from 2026 onwards. CHP can also play an important role in renewable heating and cooling, among others, to increase the renewable share in the building sector to 49% by 2030. In particular, the proposed Directive can foster biomass CHP on the national level by reducing the threshold for biomass-fuelled installations from 20 MW to 5 MW to account them for achieving renewable targets on the Member State level. Due to its flexible operation, CHP can also help to offer system flexibility and balancing services on the distribution level, which shall be permitted for small and medium systems.

A second important pillar for the energy policy of the European Union is the Energy Efficiency Directive (EED). Even if the current Directive has been revised as recently as 2018, setting a 32.5% efficiency target compared to the baseline defined in 2007 (Directive (EU) 2018/2002), the more ambitious emission reduction target for 2030 must be reflected in a recast Directive. Therefore, the current proposal targets a reduction of final consumption of at least 36-37% and primary consumption of 39-41%. A better coordination between existing resources to maximise the saving potentials offered by interactions and flexibility is one of the measures that shall deliver the targeted reduction in consumption. Here, especially district heating and cooling systems should aim for improved ability to interact with other parts of the energy system. CHP generation sits at the interface of both heat and electricity systems and can achieve highly-efficient primary energy use. However, the recast of the Directive also stipulates that new high-efficiency cogeneration facilities must be consistent with long-term climate policy, when providing heating from waste heat and renewable energy sources. A pathway of criteria to be fulfilled by efficient heating and cooling systems is defined, stating that until December 2025 these systems need to use at least 50% renewable energy or 75% cogenerated heat. Criteria are tightened for various intermediate years (2026, 2035, 2045 and 2050) so that by 2050 only

[11] See also Directive 2008/98/EC.

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renewable energy and waste heat are to be allowed, whereby the share of renewable energy shall be at least 60%. The recast of the Directive therefore highly encourages the use of renewable CHP for heating. The competence in the assessment of what is defined as “high-efficiency cogeneration” remains with the Member States and can therefore exceed the 10% threshold defined by Directive 2004/8/EC. A harmonized European approach is not to be expected.

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2 CHP participation in different markets

The high-efficiency biomass-drive CHP unit to be developed in the framework of this project will participate in several markets (beyond the potential for self-consumption of the energy it generates or transforms). These markets are subject to different regulations and the goal of this section is to assess the main regulatory aspects of CHP participation is such markets. First, the electricity market is analysed, going through all its segments. Then, heat markets are assessed, focusing on district heating. Finally, other markets relevant for CHP are analysed, ranging from the market for emission allowances to competitive support schemes.

2.1 Electricity market

Electricity markets in Europe have to follow the EU target model and are all based on a very similar set of segments. In Figure 13, these segments are classified according to the time frame and the aspect they cover, but other classifications are possible.

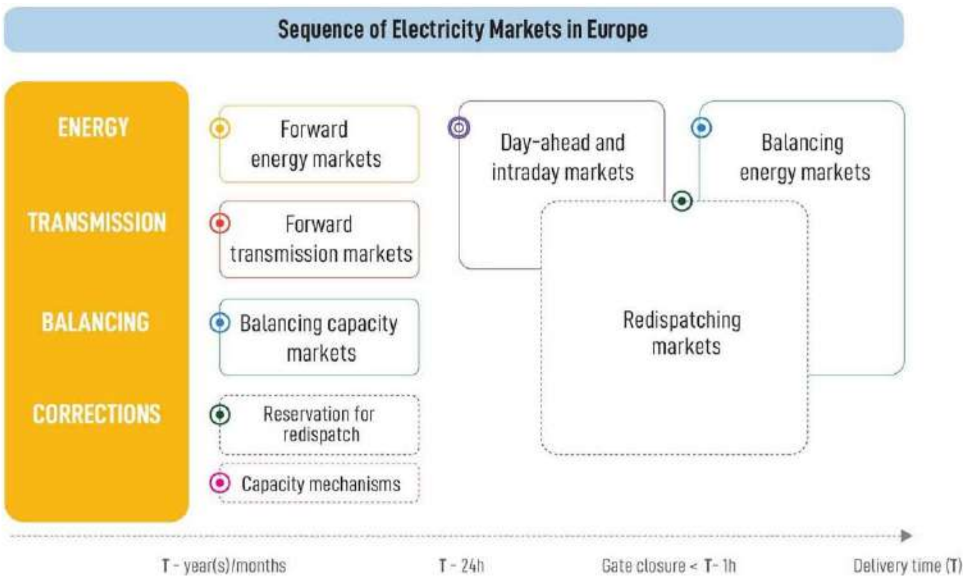

Figure 13. Electricity market design in Europe (FSR, 2020)

In this subsection, the focus is on those market segments that are present in all European markets and that produce the largest revenues for market participants: the day-ahead and intraday markets, balancing markets and markets for other flexibility services, and capacity or resource adequacy markets.

2.1.1 Day-ahead and intraday markets

In the day-ahead market, electricity is traded one day before actual delivery. This trade usually happens in power exchanges operated by the so-called National Electricity Market Operators (or NEMOs). Demand and supply present bids, according to specific bidding formats that may vary in each country, and the market is cleared at the marginal price. The market clearing produces commitments for market agents, which can be later modified in the intraday market. The latter can take the form of continuous trading or discrete auctions, although both modalities coexist in the target model. Any

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imbalance from the commitments raising from the day-ahead and intraday market will have to be settled in the balancing market.

The participation of CHP plants in the day-ahead electricity market depends on the technical configuration of the plant, its size, and the end uses it serves. The broad heterogeneity of technologies that can be embraced by the CHP label makes an analysis of this participation very complex. As mentioned in subsection 1.2.6, after the Clean Energy Package, large-scale CHP units are required to operate in the electricity market under the same market rules as the rest of the electricity generation fleet, subject to a merit-order dispatch. This approach aims at taking advantage of the flexibility that CHP can provide to decarbonising power sectors. However, the flexibility that the plant can offer and its optimal bidding strategy depends on the factors mentioned above.

Some CHP power plants treat electricity as a by-product of heat generation, thus the marginal cost of its electricity production is close to zero. Some CHP power plants rely on technological solutions that improve their flexibility, as thermal storage or a separated boiler for heat-only generation. Some small-scale CHP power plants may still be eligible for priority dispatch; others may be not eligible for it, but their installed capacity is too small to participate in the market and they outsource their participation in the electricity market to a representative party, which may aggregate its capacity to other resources (Zapata Riveros et al., 2015).

All these situations correspond to a different bidding strategy in the day-ahead market. The academic literature offers several studies on CHP bidding strategies. Kumbartzky et al. (2017) analyse the case of a CHP unit with heat storage operating in the German day-ahead and balancing market. Blanco et al. (2019) study the participation in the day-ahead market of a district heating system where heat can be produced by CHP units or heat-only units, e.g., gas or wood chip boilers. Schledorn et al. (2021) evaluate which bidding formats are more suitable for CHP (with district heating) participation in the day-ahead market.

If a CHP unit expects a modification of its dispatch that will affect its ability to fulfil the commercial position cleared in the day-ahead market, it can modify it in the intraday market. Two different designs have historically been used for these markets: discrete auctions and continuous trading (for details, see Ocker and Jaenisch, 2020). Continuous trading allows market agents to modify their commercial position as soon as they observe the possibility of an imbalance, while discrete auctions tend to offer a higher liquidity. Figure 14 presents the churn factors (volume traded in the market expressed as a multiple of physical consumption) for different European intraday markets, divided among auctions and continuous trading. The two designs have been merged in the European target model and all countries will have to adapt their intraday market design.

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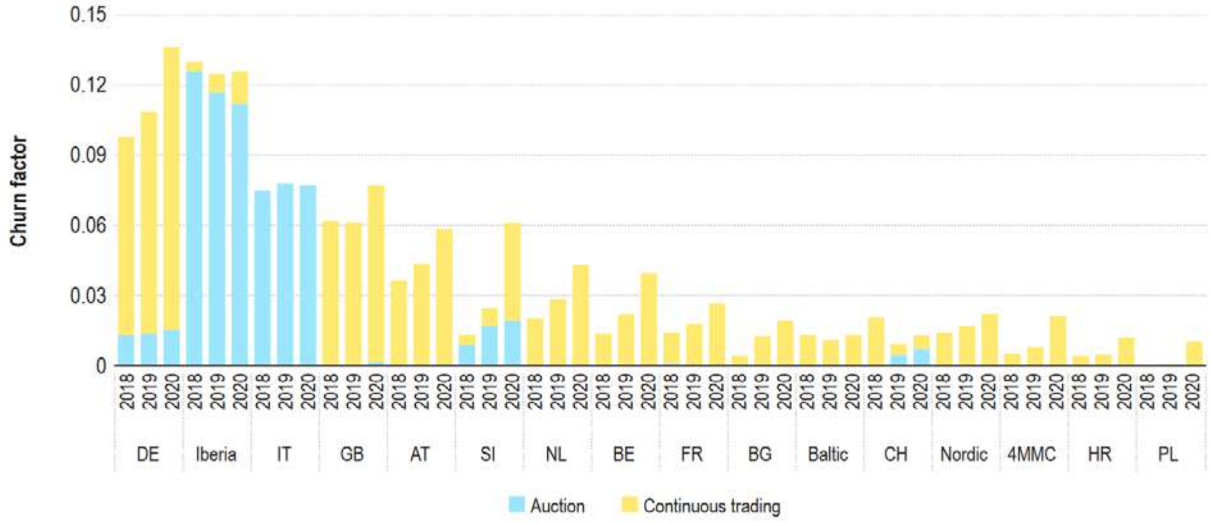

Figure 14. Churn factors of European intraday markets (ACER, 2022)

2.1.2 Balancing and non-frequency ancillary services

Balancing markets are frequency-related ancillary service markets. These markets are used for trading products that ensure the operational stability and security of the system. Balancing markets are facilitated by the TSO of the corresponding region. If there is an imbalance between generation-demand levels, the frequency will deviate from the set point of 50 Hz, resulting in cascading outages if it is not resolved quickly. Balancing markets perform this by maintaining different types of reserves to respond during such an event. Depending on the response rates, balancing products can be classified into frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR), manual frequency restoration reserves (mFRR) and replacement reserves (RR), as given in Figure 2 (ENTSO-E, 2018).

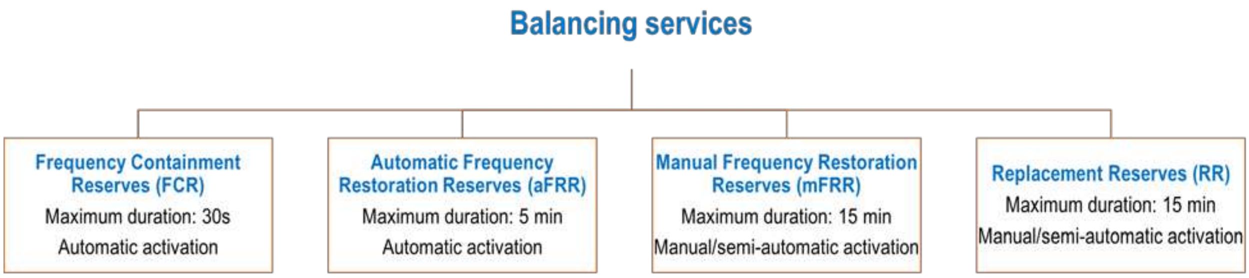

Figure 15 Classification of balancing products

Frequency containment reserves are provided by active power plants in the grid. The FCR intervenes automatically within 30 seconds when a frequency deviation is detected. If the disturbance persists after 30 seconds, the automatic frequency restoration reserve (aFRR) is automatically activated. The maximum time aFRR can contain the deviations is 15 minutes, after which manual frequency restoration reserve is activated. If the disturbance still exists 15 minutes after the activation of mFRR, the replacement reserve is manually activated. Depending on the distance from the event's occurrence, the response times of the activated product increase (ENTSO-E, 2018).

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For each of these services, the TSO determines the amount required, procures the required capacity in the balancing capacity market and activates if required in the real-time operation. The balancing products should have specific requirements (time-related and quantity-related), allowing them to respond to a system disturbance. Hence, only a few market players can provide these services. Market players providing the service are called Balance Service Providers (BSPs). BSPs have to undergo prequalification to verify whether their resource can provide the balancing services.

However, participation in the balancing market is not limited to the BSPs and TSOs. The balancing market also acts as a penalty system for market players who deviate from their positions. Every generation or consumption or storage unit is assigned to a balance responsible party (BRP) who is responsible for maintaining a balanced position (real-time position = committed position). If the BRP has an imbalance during the real-time operation, they will have to pay an imbalance price that is proportional to the imbalance they created. Hence, the additional cost that the TSO spend solving the imbalances in real-time will be forwarded to the BRPs who had an imbalance position, disincentivizing imbalance positions in future.

The integration of balancing markets in Europe is progressing slightly differently than DA and ID markets. Compared to the wholesale markets, balancing markets deal with four different products. Therefore separate platforms are made for the products, considering the individual requirements. The aFRR platform, called PICASSO, is expected to be fully implemented by 2024 ("AFRR-Platform Accession Roadmap" 2021). The mFRR platform, MARI, will be implemented by the second quarter of 2022 and TERRE, the platform for sharing RR, is already operational with 6 members ("TERRE" n.d.; ENTSO-E, n.d.).

2.1.2.1 Non-frequency system services

Apart from the balancing markets, there can be submarkets for trading non-frequency related products and services. Ancillary services like voltage regulation, black start, and reactive control are necessary system services that ensure the system's operational security. The procurement of these services is mostly contract-based (ENTSO-E, n.d.). With rising renewable penetration and the adoption of new technologies, these services might move to market-based procurement. Another submarket that is gaining importance is the congestion management market. Due to the zonal model considered for market-clearing in Europe, technical constraints are not taken into account. The congestions that arise due to it will be addressed later in a congestion management market (also called re-dispatch markets) or through mandatory re-dispatch provisions (Hirth and Schlecht, 2020).

Congestion can be alleviated in different ways ranging from topological changes to bidding zone reconfiguration (Hirth et al. 2019). The Capacity Allocation and Congestion Management Guideline (CACM) addresses the issue of congestion and proposes solutions for alleviating it. This includes close monitoring of the congestion inside and across the bidding zones, reconfiguring the market zones to reflect the congestion, and managing congestion through countertrading or re-dispatching (EC, 2015b).

Market-based re-dispatch or congestion management market is normally facilitated by the TSO. If the distributed system operator (DSO) identifies possible congestions within the distribution network due to the dispatch schedules, he/she will inform the TSO about it. The TSO will, in turn, manage the congestion along with the transmission system constraints. However, the increased share of distributed generation connected to low voltage networks is causing congestions more frequently at

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the distribution level. Directive 2019/944 recommends DSO facilitates local congestion management markets. Despite many pilot projects on local congestion management existing in Europe, market-based procurement of congestion management products by DSOs has not achieved maturity yet (Attar et al., 2022).

2.1.2.2 Challenges of CHP in balancing and non-frequency ancillary services

The participation of CHP plants in balancing markets and non-frequency ancillary markets will be determined by their technical characteristics (e.g. ramping rate, activation time, activation type) of the plant. If qualified, CHP plants have the potential to offer ancillary services to the grid. Many studies have looked at the provision of aFRR services by small-scale and medium-scale CHP plants (Korpela et al., 2017; Panos and Kannan, 2016). Notably, the potential of decentralized biomass-CHP plants to manage the fluctuations in the renewable energy production in the Swiss electricity network was demonstrated by the project CHP Swarm (Paul Scherrer Institut, n.d.).

A barrier to the participation of small-scale and medium-scale CHP plants in the ancillary services markets is the bid size. Ancillary services normally have a minimum size (normally between 1-10 MW) that might limit the participation of technically eligible CHP plants. In such cases, aggregation can be beneficial. Andersen and Lund (2006) studied the participation of aggregated small-scale CHP plants in Nord Pool and found that CHP partnerships (aggregated CHP plants) and software tools for their coordination can enable their participation in ancillary services markets.

Another factor of high concern, unique to CHP plants, is the linkage between heat and electricity output. The upward or downward regulation of electricity affects the boiler temperature which in turn affects the operation of all connected components. The plant owner thus has to consider electricity, heat and fuel price (during the scheduling period and also in future for compensating the rise/fall in temperature) for calculating the bid price (Andersen and Lund, 2006). An alternative is to use a heat accumulator to respond to the changes in operating conditions. Wang et al. (2019) shows that the flexibility of a CHP plant can be increased by using a heat accumulator and activating bypass operations. A similar study from Finland uses district heating as the heat accumulator to offer aFRR services to the grid (Korpela et al., 2017). In this case, the temperature of the CHP heat output should not differ more than 10°C from the output of the remaining plants connected to the same network, setting constraints on the offer bid volume.

The studies from the CHP Swarm project that analysed different scenarios for CHP plant operations in 2050 found that biogenic driven cogeneration has the potential to provide around 22-44% of the total aFRR requirement in Switzerland (Panos & Kannan, 2016). Currently, the main competitors for CHP plants in balancing markets are hydropower and large-scale gas turbines. However, unlike hydropower which is location dependent, CHP plants have geographical flexibility making it a good option for markets with high congestion. In future, batteries and demand response might emerge as competitors for CHP plants.

Also the Danish experience provide valuable insights on CHP participation in flexibility markets. CHP plants in Denmark, where biomass accounts for around 20% of the net power production, shows that the CHP plants can increase their participation in the ancillary services market by retrofitting their hardware and changing their business use cases (Danish Energy Agency, 2021). During the period 2010-2015, the penetration of vRES increased in Denmark, forcing the CHP plants to move from baseload operation to flexible operation. A major factor that enabled the move was the decoupling of heat and

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electricity production. Otherwise, the plant will have a must-run condition imposed on it, forcing it to run at submarginal-cost conditions.

In many countries, the participation of CHP is largely limited to day-ahead and intraday markets (Awais Salman et al., 2021). Flex4RES, a Nordic demonstration project for high RES penetration challenges, concluded that the market prices in Nordics are not favourable for CHP flexibility (Bergaentzlé et al., 2016). A recommendation from this report is to create subsidies for CHPs and P2H technologies to encourage their participation, especially in the systems that require a high amount of generation flexibility. This is especially relevant for countries opting for fast-paced decommissioning of fossil-fuel plants where a part of the old plants can be replaced by the CHP plants (Kopiske et al., 2017).

2.1.3 Resource adequacy

Resource adequacy is one of the main challenges for decarbonising power sectors. The penetration of large shares of intermittent and non-dispatchable generation creates new interdependences in the power system, which, in some case, may amplify existing reliability issues or create new ones. Extreme weather events, whose intensity and frequency are growing due to climate change, are also having an impact on the security of electricity supply, as the energy crisis that affected Texas in 2021 demonstrated (Busby et al., 2021).

In liberalised power sectors, resource adequacy issues are commonly addressed through capacity remuneration mechanisms (CRMs). These regulatory instruments complement the economic signal conveyed by the energy market and provide a more predictable remuneration to market agents, reducing the risk they perceive and fostering the investment required to guarantee the security of supply. Different CRM designs have been proposed and implemented in the European Union, as shown in Figure 16 (for a detailed theoretical discussion on the design of CRMs, see Batlle et al., 2015).

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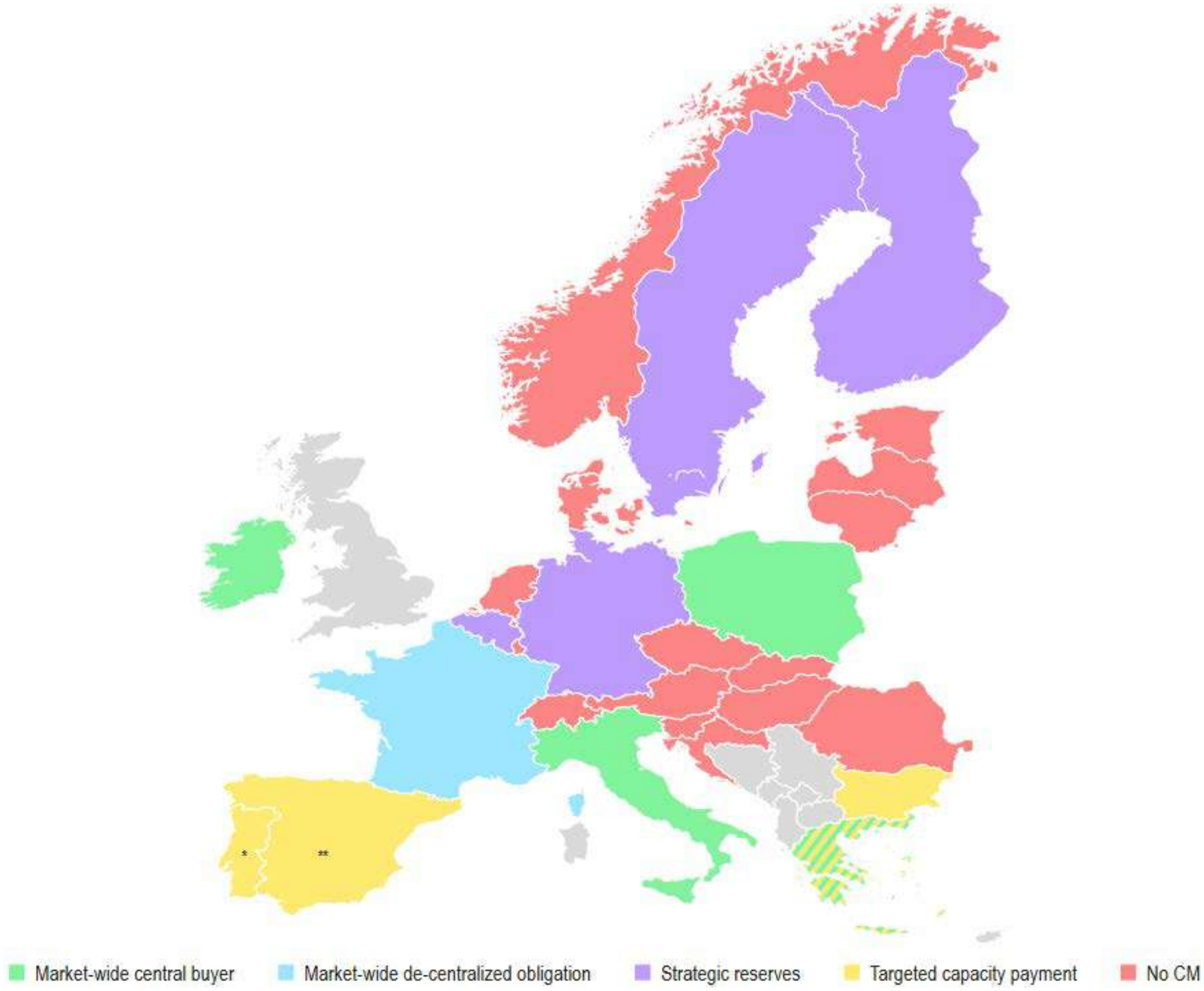

Figure 16. Capacity remuneration mechanisms in the European Union (ACER, 2022)

Capacity mechanisms should remunerate resources for the contribution to reliability they can provide to the system. Combined heat and power can definitely contribute to the reliability of the power sector; therefore, it should be able to participate in CRMs and obtain the consequent remuneration, which, in certain countries, may substantially improve the financial viability of the project.

However, the contribution of CHP to the security of supply depends on several factors. Some of them are related with the kind of scarcity conditions that are expected in the power system in the future and the reliability product designed to solve them, which is then procured in the framework of the capacity market. Other factors are related with the final use and the technical features of the CHP plant itself, which could make it more or less suitable to provide the specific reliability product defined for the power sector which it is connected to.

2.1.3.1 Size and emission thresholds

Some design elements of the capacity mechanism can explicitly constraint that participation from CHP plants. Most of CRMs apply some kind of capacity threshold. For instance, in the United Kingdom, this threshold was recently reduced from 2 MW to 1 MW to favour the participation from small-scale units (BEIS, 2021a). Also Belgium is applying a 1-MW threshold for participating in its CRM (Elia, 2021), but the limit is not on the installed capacity but on the de-rated capacity (see subsection 2.1.3.3 for details).

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Obviously, cogeneration units smaller than these minimum sizes can still participate in the CRM by aggregating with other resources, but this may complicate the process.

Capacity mechanisms are also subject to emission thresholds. The Clean Energy Package imposed stringent emission limits for European CRMs.

- from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;
- from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO2 of fossil fuel origin per kWh of electricity and more than 350 kg of CO2 of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism.

This may constraints the participation of both existing and new CHP units. The regulation mentioned above does not specify how to compute emissions and this topic is even more complex for cogeneration, since emissions should be distributed between two energy vectors and there is no obvious solution for that. ACER (2020) provided some examples of emission calculation for CRM thresholds and one of them regards CHP; ACER methodology apparently disregards the heat production when assessing the efficiency and the emission of the cogeneration plant.

Some regulators have proposed methodologies that try to recognise the higher overall efficiency of CHP units when calculating these emissions. The United Kingdom proposed to apply an alternative formula when calculating the electrical efficiency of a CHP installation, which takes into account the electricity that could theoretically be generated from the high-pressure steam which is produced and utilised as part of the generation process (BEIS, 2020).

It is interesting to note that emission limits have also been used to favour CHP units in the capacity market. For instance, according to Zamasz et al. (2020), in Poland, high-efficiency cogeneration may prolong the duration of a capacity agreement concluded during an auction by two additional years (the so-called green bonus), in case the generation unit: i) keeps the specific CO_2 emission factor at the level below or equal 450 kg CO_2/kWh of generated electricity, and ii) at least half of the heat generated in such a unit is transferred to the heat distribution system, with its carrier being hot water.

2.1.3.2 Design of the reliability product

The reliability product is the product that is traded in the capacity market to guarantee the security of supply. Very different reliability products have been implemented so far. Some of them focus on the availability of the resource, others are coupled with a financial option that protects the buying side also from price spikes, others include some technical requirement (as start-up time of ramping rates) or require resources to be able to participate in certain market segments (as the balancing market).

The design of the reliability product may limit the participation to CRMs from certain CHP units. An aspect of particular importance is the final use of the heat produced by the CHP plant. In many cogeneration facilities, heat is the main product and electricity is considered as a by-product associated to the main one. This limits the flexibility that the resource may provide (see subsection 2.1.2). If the

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reliability product and the CRM in general specifically target flexibility, then some CHP units may not be able to participate.

There are energy strategies to improve the reliability services that can be offered by CHP plants, as analysed in (Ito et al., 2017). The installation of thermal storage, which partially decouple heat and electricity productions, is certainly one of them.

2.1.3.3 De-rating and firm capacity calculation

The amount of reliability product that each resource can trade in the capacity market is commonly constrained by the application of a de-rating factor. The latter is a factor that is multiplied by the installed capacity of a resource in order to obtain its firm capacity, i.e., the capacity that such resource will be able to provide to the system during the scarcity conditions expected for the future. The methodology for the calculation of de-rating factors for different technologies is an aspect of paramount importance in the design of the CRM and it also has an impact on the development of the power sector and its resource mix.

Also in this case, very different approaches can be identified, ranging from the use of historical production data to complex methodology encompassing simulation models. As regards combined heat and power, it is quite common for these units to be equated to thermal power plants of the same technology. For instance, in the United Kingdom, CHP units are recognised a 90% de-rating factor (a 100-MW CHP unit is recognised a 90-MW firm capacity), the same value used for CCGTs (National Grid ESO, 2020). In Belgium, CHP units are granted a 93% de-rating factor, even higher than most of thermal power plants (Elia, 2021).

This approach completely disregards the operational strategies of most CHP units. As already mentioned, many of these facilities treat electricity as a by-product and the operation of the plant may give higher priority to heat production. Some of these plants may not be able to provide the reliability service to the power system right in the moment when the operator requires it. By recognised to these plants the same de-rating factor as other thermal plants may unduly favour CHP in the capacity market. This approach also provides no incentive to strategies that would allow to improve the contribution of CHP to the reliability of the system, as the installation of thermal storage. Finally, it must be remarked that a high de-rating factor may provide a higher remuneration from the capacity market, but if the unit is eventually not able to fulfil its reliability commitments, it will be subject to significant sanctions and penalties.

2.2 Heating market

2.2.1 Heat networks and decarbonisation

Heat networks are expected to provide an increasing share of domestic heating. They deliver heating, hot water, and/or cooling from a central source or sources to a variety of different customers such as domestic residential units, public sector buildings, shops, offices, sport facilities, universities. Heat networks are a crucial aspect of the path towards decarbonising heat and achieving net-zero commitment. Heat networks can be supplied with renewable or residual heat to achieve the climate targets (BEIS, 2021; EZK, 2019).

The technical differences between heat networks are mainly driven by the heat production technology: residual heat, biomass, potential for storage, heat pumps or geothermal energy. The

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technology for heat production largely determines the environmental sustainability of the heat supplied. The lifetime of a heat network is generally longer than the lifetime of heat production facilities. Individual heat-only boilers, electric heating, CHPs are the main heat production technologies. However, there is a broad range of low-carbon technology options for networks (EZK, 2019).

In the right circumstances, heat networks deliver good-quality outcomes for consumers, support local regeneration and can be a cost-effective way for reducing carbon emissions from heating. On the other side, CHP plants are a highly-efficient production technology and can deliver additional carbon savings, since they simultaneously generate electricity that can be utilised by consumers on-site or exported to the grid. However, the carbon savings of gas-driven CHP plants are being reduced as the carbon emissions of grid electricity falls. As we move towards 2050, we know that meeting our climate targets will require a transition from gas-fired networks to lower carbon alternatives such as biomass, large heat-pumps, hydrogen or waste-heat recovery (BEIS, 2021).

2.2.2 District heating networks

There are two types of heat network: communal heat network (serving only one building), and district heat (DH) network (serving multiple buildings; BEIS, 2021). In Nordic countries, heat is traded through DH network that is widely used to cover the heat demand. DH has a big advantage because it is flexible regarding both fuels and heat generation technologies and when coupled with CHP (DH/CHP) can help to balance the fluctuations in the power system and thereby support the integration of wind power. Some technical measures can improve the flexibility of the DH/CHP system and can help integrate wind power, for example, heat storages, electric boilers and heat pumps, and bypass of turbines. By use of heat storage, DH plants can decrease their CHP production when there is sufficient electricity from wind turbines in the system and still be able to supply heating from the thermal storage. By using electric boilers and heat pumps, DH plants can use excess electricity from wind turbines directly for heat production. In some CHP technologies, by bypass of turbines, a CHP plant can avoid generating electricity when there is excess in the system. Instead, it can produce only heating with the same efficiency as a heating-only boiler. The flexibility of the DH/CHP system is therefore an important aspect regarding integrating a large share of wind power into the energy system (DEA, 2017). Table ii provides overview share of CHP in DH in Sweden and Finland which are among the top five countries with a high share of DH in heat network.

Table ii. Statistics of share of CHP in DH in Sweden and Finland

Country	Sweden (SEA, 2019)	Finland (FE, 2019)
District heating consumption (2019)	56.3 TWh	33.2 TWh
Share of space heating demand supplied by DH (2019)	Ca 50%	46%
Electricity production from CHP plants in DHS (2019)	9 TWh	11 TWh
Share of yearly national electricity consumption covered by CHP plants	Ca 6.5%	13%

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2.2.3 Tariff regulation in district heating networks

Unlike in the electricity and gas sector, DH suppliers are not in direct competition with each other, since DH systems are predominantly designed as isolated systems that are not connected to each other (Wissner, 2014). Heat cannot be transferred between regions except a few cases in which DH companies have shared the same heat network in neighbouring communities. An established heat network has the characteristics of a natural monopoly. This leads to a call for extra supervision and regulation on heat suppliers (EZK, 2019). This means that customers cannot choose between different DH providers. Also, there is no wholesale market for DH due to technological limitations. Furthermore, incentive regulation that is in place for gas and power grids does not apply to DH distribution grids.

DH companies can operate under regulated or non-regulated terms. In many countries, the supply of heat is regarded as a service of public interest/communal service and the provision of this service is subject to the rules defined by national and local authorities. There is only regulation of end-user prices at the local level (ESC, 2021). On the other hand, DH tariffs may be set by DH companies that set the end-user price based on the opportunity cost of consumers (instead of a cost-plus approach or a cost-of-service regulation) in non-regulated DH. Differences of regulations in EU Member States is shown in Figure 17 (EC, 2021g). In more than half of the analysed countries, the prices are regulated, but the depth of the regulation differs. Two main models for price regulations are liberalised DH prices and regulated DH prices. In liberalised price, there is ex-post price control on request (e.g., Sweden, Finland, Germany), while in regulated price, there is mandatory price control (e.g., Denmark, Bulgaria, Lithuania, Netherland Poland, or Slovakia).

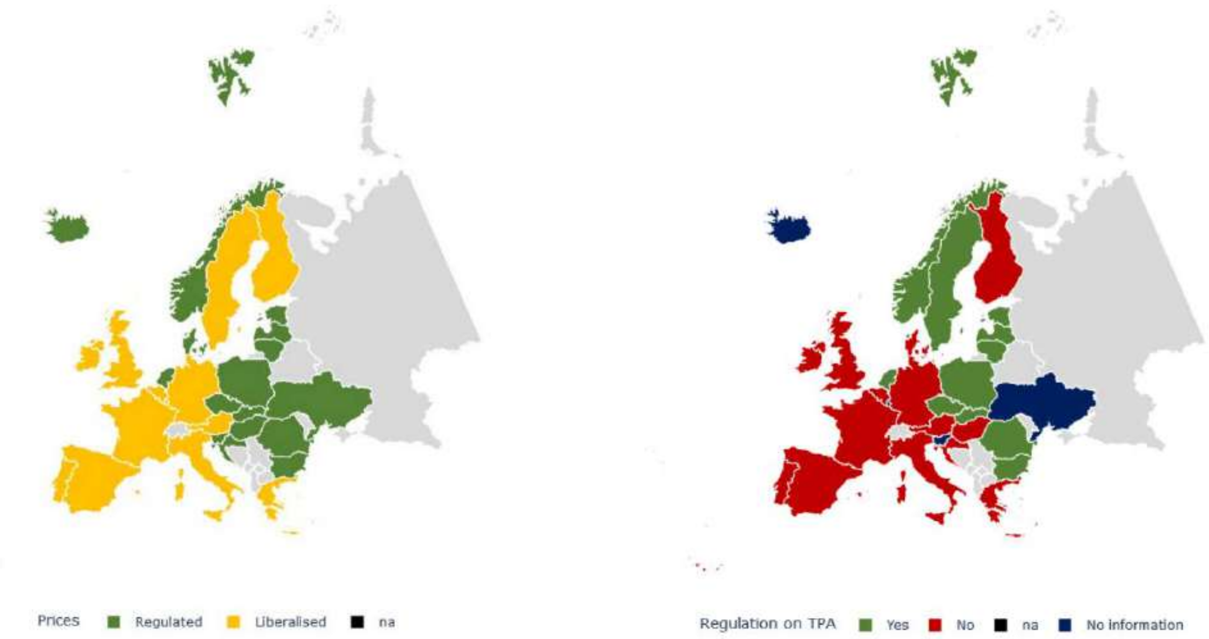

Figure 17. Maps of price (in the left) and third-party access regulations for EU member countries (EC, 2021g)

Heat market characteristics depend on technical and geographic differences, local political situations and commercial decisions leading to DH networks with different scales and organisation. A statutory framework underpins the regulation of all heat networks. The regulatory framework should be

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designed to ensure that all heat network customers are adequately protected (BEIS, 2021). Regulation protects consumers against excessive tariffs and encourages heat suppliers towards efficient operations, investment and service levels. In addition, good regulation takes the local situation into account, contributes to the investment climate and enables sustainability objectives (EZK, 2019).

Municipalities play an important role in the establishment of a heat network (see Figure 18). The party that is developing or refurbishing an area (within the framework set by the municipality) negotiates with a heat supplier on the conditions for constructing or expanding a heat network. The heat supplier generates its revenue from (future) customers in the area. At the moment, the rates do in general not cover the full costs. That is why a cost recovery contribution is often required to install the heat network. The cost recovery contribution is paid by the owner of the property or passed on by the developing party in the price of a building. This way the consumer pays for part of the heat network via the purchase or lease of the building and part via rates for heat.

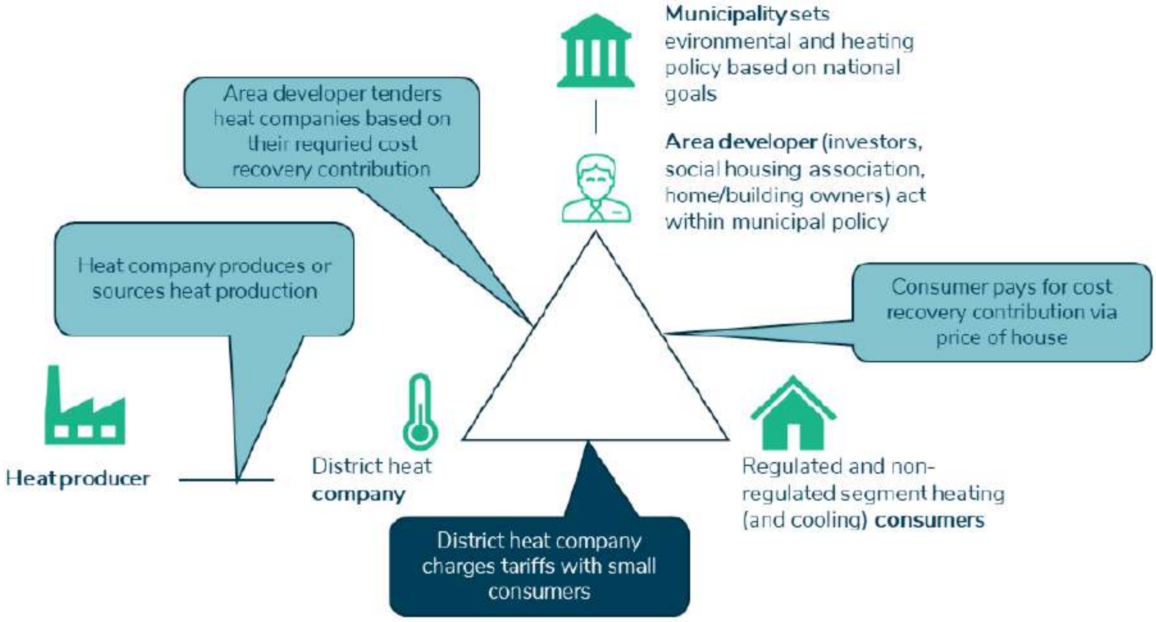

Figure 18. Heat network tariff regulation (EZK, 2019)

The principles of tariff setting in regulated industries are summarized in (ECS, 2021). Authorities mostly use one of the following methods on tariff regulation:

- Rate of return/cost plus
- Revenue cap
- Price cap
- Benchmarking
- Hybrid method

In the Rate of return/Cost plus methodology, justified costs of operation and the return on the capital invested are included. In the Price and Revenue cap methods, the maximum amount of revenues/prices is set in advance for a fixed period of one or several years (“regulatory period”). As mentioned in the Figure 17, there are two main models for price regulations (liberalised and regulated). In the countries with explicitly regulated price, the cost-plus method is usually applied, but

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in the liberalised DH price countries, prices are formed in the market (EC, 2021g). The Benchmarking method of tariff setting does not reflect the true cost of heat production, as it sets the tariff in relation to alternative sources of heat, such as gas or electricity, or sets the tariff in relation to the average costs in the respective industry in other countries. The downside of adopting the Benchmarking methodology is that the payment for heat by consumers may not cover the cost of the primary fuel delivered to consumers. All these methods may be combined, and hybrid approaches might be developed. The final DH tariff for end-users consists of components including production, transportation, and supply costs covering operating and capital costs.

For small consumers of DH, three ways of regulation using an assessment framework have been examined in (EZK, 2019). Three alternatives for tariff regulations are:

- Tariffs set by the heat supplier combined with transparency rules
- National reference rates set by the regulator, possibly by technology
- Rates set by a regulator per heat supplier or heat network

In the first alternative, heat suppliers set their own rates subject to conditions regarding transparency of tariffs and costs. Regulator monitors transparency of costs that can be supplemented with “price dialogues” in which a heat supplier discusses tariff developments with customers. In the second alternative, a heat supplier cannot set rates above the reference. The reference can be determined based on productivity index or possibly per heating technology. Changes in efficiency and technology in the sector can be used to adjust rates in the future. This gives confidence to the small consumer and leads to fewer assumptions to calculate the cost recovery contribution required to make the investment profitable. In the third alternative, the regulator could set rates based on the costs of a heat supplier. These cost-based rates may differ from network to network, or supplier to supplier.

In most European countries, heat suppliers have commercial freedom to set the tariff, supplemented with supervision by the competition authority and local agreements. In Denmark, there are two ways to include CHP in heat tariff. If the DH company owns the CHP plant (and many DH companies do), the income from power production is included directly in the budget and heat tariffs are lowered according to income. If the DH company does not own the CHP plant, the heat delivery (i.e., the heat part of the costs) tariff is negotiated. In the CHP cost-allocation methodology, CHP can maximize its profit by selling electricity. However, there is a regulation that applies to small-scale CHP plants that forbids them from earning a profit on electricity generation as well (USAID, 2021).

Among the three alternatives, there is not one way of regulation that scores best based on the assessment framework. Customization of regulation is desirable. Each way of regulating has its advantages and disadvantages and possibly hybrid forms are desired (EZK, 2019). In all heat networks markets, both non-regulated and regulated, price transparency is a key factor to ensure consumer benefit. In non-regulated markets, the effectiveness of transparency protects consumers from unfair pricing. The regulations and pricing on heat network are different in different countries. In Sweden as a non-regulated market, suppliers must publish yearly reports to allow price comparison. There is also voluntary initiative such as “price dialogue”, requiring price forecasts for the following two years, increases transparency (BEIS, 2021). Regulations and pricing for DH in Sweden and Finland are briefly described in Table iii.

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Table iii. Size and price regulation of DH of countries

Country	Sweden (CXC, 2018)	Finland (FE, 2020)
Type of Price Regulation	Voluntary pricing scheme; price transparency	Seasonal prices set by companies to cover the production cost
Length of network	23400 km	15570 km
Number of DH schemes	500-600 systems operated by over 200 companies	100 companies supplying DH in about 178 municipalities

2.2.4 Third-party access in district heating networks

In DH, the heat network and the production plants are mostly owned by the same company. On the other hand, there are also many networks, where a significant share of DH comes from third-party producers, typically from industrial CHP plants or waste heat sources. When the supplier of the heat production is different from the distributor through the network, we call about third-party access, and this is usually based on voluntary agreements between the third-party producers and DH companies (Pöyry, 2018).

Third-party access has been presented to improve energy efficiency by utilising more renewable energy. However, these targets are already promoted by other policy measures, such as emissions trading, energy taxation and building codes. Because the DH system operations, such as heat production, sales and distribution, are currently integrated, any regulated third-party access would require significant changes to the current systems and regulation. Third-party access can be implemented with a variety of market models and levels of regulation. It is possible to introduce competition only to the production of heat, or to open the networks for direct supply of third-party produced heat to customers. Based on this difference, the potential models can be classified as single-buyer models or network-access models. However, the impact of any third-party access for small consumers is limited (EZK, 2019). The two models are analysed in more detail in Pöyry (2018). The analysis in EC (2021g) reveals that there is not any obvious correlation between degree of market opening of DH systems and share of renewables or excess/waste heat.

Söderholm et al. (2011) analysed the possible effects of introducing third-party access in DH. Based on different scenarios, regulated third-party access, negotiated third-party access, and single-buyer model have been analysed in Swedish DH. In all scenarios, the network owner has an obligation to allow access to the network from the companies that so wish. They concluded that regulated third-party access may have small positive effects on competition, and at the same time it can have a negative impact on the possibility to run the integrated DH operations in a cost-effective manner. The introduction of the single-buyer model or, perhaps even preferable, an extended and more transparent producer market could represent a more efficient market design.

The possibility to open the networks for third-party production with more transparent conditions has been discussed on national and on EU level lately. However, Council of the European Union and European Parliament suggest that for efficient DH systems, the third-party access should be based on

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so called single-buyer model, or the renewable share of production can be increased by other means (Pöyry, 2018).

2.3 Other markets

2.3.1 EU ETS

The European Union Emission Trading System (EU ETS) is a market for emission allowances putting a cost on greenhouse gas emissions. The EU ETS is a single market that covers stationary emitters in the European Union, Iceland, Liechtenstein, and Norway and has been introduced almost two decades ago. The foundations of the EU ETS were laid down in Directive 2003/87/EC with phase 1 commencing operation in 2005. From the start, the EU ETS covered the entire power system and some industrial applications. As of November 2021, 10 569 power plants and manufacturing installations take part in the EU ETS, including all power stations and combustion installations with >20 MW thermal rated input, various industries, and carbon capture facilities (CCS/CCU) (ICAP, 2021). Additionally, aviation has been included to the system in 2012, but it does not actively participate in the EU ETS yet.

The underlying premise of the EU ETS is that emitters pay a premium for CO_2 and other greenhouse gases released to the atmosphere, thereby weakening their business case and incentivising less emission intensive practices. Emitters are obliged to obtain emission allowances, the right to emit one ton of CO_{2e}, corresponding to their total yearly emissions and surrender them to the national competent authority by April 30th for the past calendar year[12]. Installations in sectors covered by the EU ETS but emitting little or no emissions benefit from the scheme of tradable quota, since they must pay only a small or no emission premium compared to their emission-intensive competitors. Allowances are auctioned by EU Member States at the national level and can be traded between market participants via a centralised market platform, resulting in a market price for free allowances. The market price is subject to daily fluctuations and can be characterised by a significant long-term volatility[13].

The market design of the early phases has been far from perfect and was under scrutiny for, amongst other, low prices and dynamic inefficiency, insufficient coverage, and competitiveness concerns (Hepburn et al., 2017). Even though EU ETS emission allowances have experienced a price rally since 2017, jumping from about 4 €/tCO2e to price peaks beyond 95 €/tCO_{2e} in early 2022, concerns about their effectiveness to price emissions in the industrial sector remain. On January 2021, the EU ETS entered phase 4, which is expected to last until 2030. Due to the ongoing political debate and the policy actions that will follow the publication of the EU “Fit for 55” package, it is expected that the current market design for phase 4 will be revised to include a carbon border adjustment mechanism (CBAM) and accelerate the phase out of free allowances. Basis for the following analysis is the current phase-4 market design, as specified in Directive 2018/410.

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[12] Every year, operators must submit an emissions report. Data for a given year must be verified by an accredited verifier by 31st March of the following year. Once verified, operators must surrender the equivalent number of allowances by 30th April of that year.

[13] See the secondary EEX spot, futures and option markets development for EU ETS allowances: www.eex.com/en/market-data/environmental-markets/spot-market

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2.3.1.1 Cap-and-trade

The EU ETS follows a cap-and-trade approach. The availability of allowances that grant the right to emit is limited by an absolute emission cap. For the year 2021 this cap was at 1 572 $MtCO_{2e}$ per year, which is set to reduce by 2.2% annually, the linear reduction factor (LRF), during phase 4. The continuous reduction of the cap creates scarcity and elevates the market price for emission allowances, while strengthening the business case for technologies, such as high-efficiency CHP operating with fossil and non-fossil resources, allowing market participants to reduce their emissions.

2.3.1.2 Free allowance allocation

Allowances are awarded in public auctions on Member State level. However, only 57% of all emission allowances are actioned and the remaining 43% are free allowances allocated based on benchmarks. Especially in the industrial sector, companies operating on global markets can cover most of their occurring emissions with free allowances, protecting them against the full carbon price and carbon leakage effects. Only the power sector is not subject to any free allowance allocation[14] and therefore paying the full EU ETS market price for emitting. Due to free allowances, the net carbon price for emissions in industry is therefore significantly lower than the market price and differs across all sectors. While electricity generation with CHP will always be subject to the full carbon price, CHP installations can be subject to very different net carbon prices for the provision of heat depending on its specific use case.

Free allowances are granted preliminary to installations based on the corresponding emission benchmark of the economic activity (BM) multiplied by the historic production data from the previous year (HAL) and the carbon leakage exposure factor (CLEF). For all activities that are not considered to be at risk of carbon leakage, the applicable CLEF has been gradually reduced from 1 to 0.3 during phase 3 of the EU ETS until 2030 and is set to reach 0 by 2030, thereby fulling phasing out free allocation for these sectors. Note, that the CLEF from district heating will remain at 0.3 for the entire phase 4 of the EU ETS.

$$F = BM \times HAL \times CLEF$$

Where:

F	Annual preliminary allocation (allowances per year)
BM	Applicable benchmark value (allowances per unit of activity)
HAL	Historic Activity level (unit of activity per year)
$CLEF$	Applicable Carbon Leakage Exposure Factor (unit-less)

Additionally, allocation might be subject to a Cross-Sectoral Correction Factor (CSCF) that can be applied in case the sum of the preliminary free allocations exceeds the number of free allowances available. The CSCF is single factor that is the same for all eligible sectors, which has been criticised for discriminating those industries that increase their production and result in an oversupply of free

[14] Exceptions exist for lower-income EU member states (GDP<60% of average)

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allowances to industries with stagnating or lower production than their historic activity level (HAL) (Marcu et al., 2021). For high-efficiency CHP for electricity generation (if eligible for free allocation) and district heating, free allowances are reduced by the LRF of 2.2% in the years that no CSCF is applied (EC, 2019c).

In its current design, phase 4 of the EU ETS already aims to phase out free allocation for all applications with minor or null carbon leakage risk, increasing the number of sectors exposed to the full emission allowance price by 2030. Free allocations would only remain for industries with a high carbon-leakage risk (CLEF = 1) and the district heating sector (CLEF = 0.3).

2.3.1.3 Benchmarks (BM)

A CHP installation can be subject to one or multiple emission intensity benchmarks within the EU ETS. Product benchmarks are based on the total emissions resulting from the production of one unit of product (ton or carbon-weighted ton, CWT). The benchmark is therefore based on the industrial output (Figure 19). The EU has set product benchmark for 52 emission intensive products based on the 10% most efficient installations within each industry. Product benchmarks are updated on a yearly basis and aligned to the reduction of the total emission cap (EC, 2021f). Product benchmarks do not cover all products produced by industries subject to the EU ETS and there are no product benchmarks for the industrial heating and district heating. Most benchmark allocation (76.2%) is based on product benchmarks.

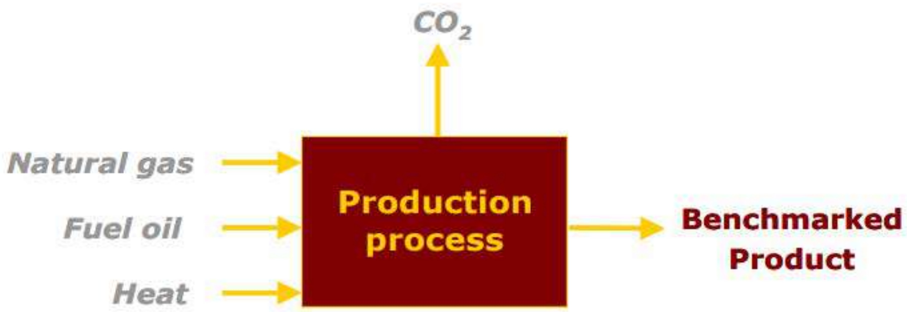

Figure 19. Example of a product benchmark (EC, 2019c)

Heat and fuel consumption benchmarks serve as a fall-back for products and processes not covered by product benchmarks. These benchmarks are set based on the energetic input to the process and the resulting emissions per TJ of energy (Figure 20). In 2021, approximately 20.5% of all allowances allocated by benchmarks are based on heat (14.1%) and fuel (6.4%) consumption benchmarks in 2021.

Current heat consumption benchmarks have been heavily criticised for using conventional gas-fired plants as reference for defining the 10% most efficient installations, inflating the number of free allowances received by CHPs independently from their fuel source. Beneficial for CHP technology in general, current heat consumption benchmarks provide little incentives for choosing renewable fuel sources over fossil alternatives (Sandbag, 2020).

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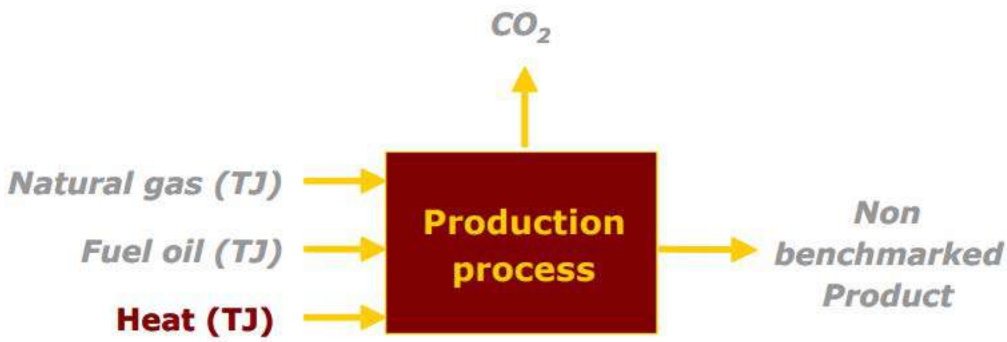

Figure 20. Example of a heat consumption benchmark (EC, 2019c)

Process emission benchmarks complement heat and fuel consumption benchmarks for industries without product benchmarks. The benchmark corresponds to 97% of historical process emissions of these installations, however covered by a 97% free allocation rate based on historical process emissions. The role of the process emission benchmark is a very minor one, only covering 3.2% of the free allowances allocated based on benchmarks and is not relevant for CHP installations.

2.3.1.4 Sub-installations

The European Commission has introduced the concept of sub-installations to correctly account emissions and identify those processes that are eligible to free allowances based on benchmark allocation (EC, 2019c). Installations are divided into sub-installations following a cascading principle, first, applying product benchmarks, then heat and fuel benchmarks and lastly process emission benchmarks. Figure 21 shows exemplary how a system is divided based on two different product benchmarks.

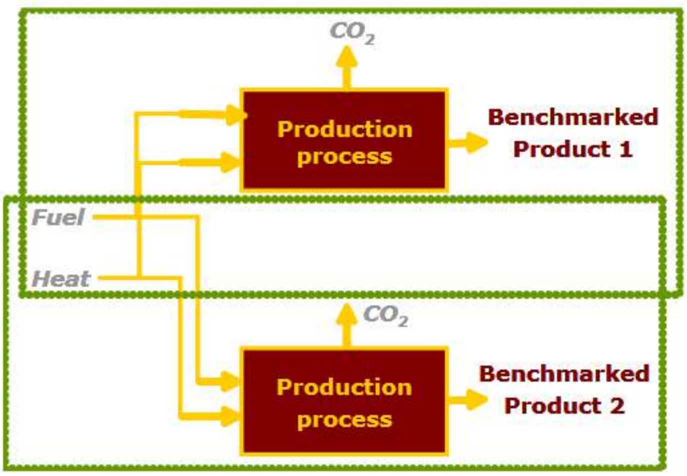

Figure 21. Division installation into sub-installations based on product benchmark (EC, 2019c)

In the case of CHP, an additional complication is the provision of two different outputs, namely electricity and heat. Whereas generated electricity is not eligible to free allowance allocation, heat might be, however, subject to whether the CHP itself and/or the heat consumer is part of the EU ETS. Table iv summarises the different use cases and the sub-installation eligible to free allocations if a CHP as heat supplier is one of the sub-installations.

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Table iv. Free allowance allocations between sub-installation and CHP (Prendergast, 2019)

Heat supplier (HS)	Heat consumer (HC)	Allowance allocation
ETS installation	ETS installation	HC gets allocations for the heat imported and consumed
ETS installation	Non-ETS installation	HS gets allocations for the heat exported to non-ETS
Non-ETS installation	ETS installation	The heat is not eligible for free allocation, as it is produced by non-ETS

A CHP installation must be part of the EU ETS to obtain free allowances allocated to stationary installation. Here, the EU ETS Directive (Annex I) sets a threshold of 20 MW thermal input as minimum criteria for including stationary installations in the EU ETS. Only heat generated with CHP that has a thermal input capacity greater 20 MW can be accounted for in a heat consuming ETS sub-installation. Note, though, that if heat from a small-scale CHP (< 20 MW) is used in combination with sub-installations subject to ETS benchmarks, the origin of sustainable heat flows is of little relevance for free allowance allocations. However, externally supplied heat reduces the fossil fuel demand and therefore the emissions of the sub-installation, bringing total emissions closer to the 10% most efficient installations benchmark or, in the optimal case, surpassing it.

2.3.1.5 EU ETS exposure for the Bio-FlexGen use cases

Table v summarises the impact of small-scale (< 20 MW) and large scale (>= 20 MW) CHP on the economics of the investigated use cases for the Bio-FlexGen project.

Table v. Accounting for benchmark allocation across different sub-installations

Heat supplier (HS)	Heat consumer (HC)	Allowance allocation
CHP with > 20 MW thermal input	District heating system (non-ETS)	HS receives heat consumption benchmark allowances for export to non-ETS *A CLEF of 0.3 ensures that free allocation continues until 2030.*
CHP with < 20 MW thermal input		No allowance allocation
CHP with > 20 MW thermal input	Cement plant / Sodium Chloride plant (ETS)	HC receives product benchmark allowances *If considered at risk of carbon leakage (CLEF =1) free allocation continues until 2030* HC receives heat import allowances

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CHP with < 20 MW thermal input		HC receives product benchmark allowances *If considered at risk of carbon leakage (CLEF =1) free allocation continues until 2030*

2.3.2 Guarantees of origin for electricity

Beyond the remuneration that the CHP plant can obtain from the day-ahead or the intraday market, the unit may also be eligible for guarantees of origin for electricity produced from renewable energy sources or high-efficiency cogeneration.

Decoupling renewable energy consumption from production allows consumers to contract renewable energy supply without constraining consumption to the supply fluctuations and availability of renewable energy sources. Guarantees of Origin (GOs) can separate physical energy production from its intrinsic production-related characteristics, such as production route, emission intensity and timing, into two different tradeable products. By purchasing Guarantees of Renewable Origin (GROs) stemming from renewable energy sources, final customers can certify that there is renewable energy being produced that corresponds to their consumption without proving that physical energy consumption is renewable. Hence, GOs are a policy instrument that introduces a distinction between different energy production routes that would otherwise be treated equally, creating additional revenue for energy sources with desirable renewable and low-emission characteristics.

The emergence of GOs in Europe is closely linked to past, current and future European commitments to sustainable energy use. In 2009, the first Renewable Energy Directive (RED I: Directive 2009/28/EC) set a binding target of 20% energy from renewable sources by 2020. In this context, GOs were introduced as a European wide validation mechanism to demonstrate to final costumers how much energy from renewable and non-renewable energy sources they purchase and consume. First GO initiatives already existed on national and European levels before 2009, though they were mostly streamlined to RED I with a strong focus on electricity, heating, and cooling. Additionally introducing sustainability certification mechanisms, RED I presented a separate approach to account for the contribution of biofuels and bioliquids to renewable energy targets.

RED I set the stage for national GOs as a validation mechanism for the composition of consumed energy that the different member states shall mutually recognise. In practice, these GOs are issued by the Association of Issuing Bodies (AIB), supported by 27 national and regional issuing bodies from 24 countries that established the European Energy Certificate System (EECS) to issue, hold, transfer, and process regulated GOs in the European Union.

Under the umbrella of the EECS, GOs for electricity consumption and heat from cogeneration have been developed as a tradeable proof per unit of energy (1 MWh) that indicates:

- The energy source from which the energy source was produced
- Whether it relates to electricity, heating or cooling
- Location, type and capacity of the installation used for energy production.
- Whether the installation benefited from support schemes.
- Initial date of operation
- Date and country of issue

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GOs are valid for 12 months after the production of energy, which allows them to be traded and sold based on the willingness to pay by other market participants via the AIB hub. The final prices paid for GOs are non-disclosed, though GRO prices between 1 - 2.5 €/MWh have been reported for 2018 and 0.40 - 0.50 €/MWh for 2019 (Lindberg, 2019). AIB market data does show how GOs are traded across member states, with a clear tendency of GO transfers from countries with a high share of low-emission electricity generation, such as France, Norway and Spain, to countries with a lower share of renewable generation, such as Germany and the Netherlands (Figure 22).

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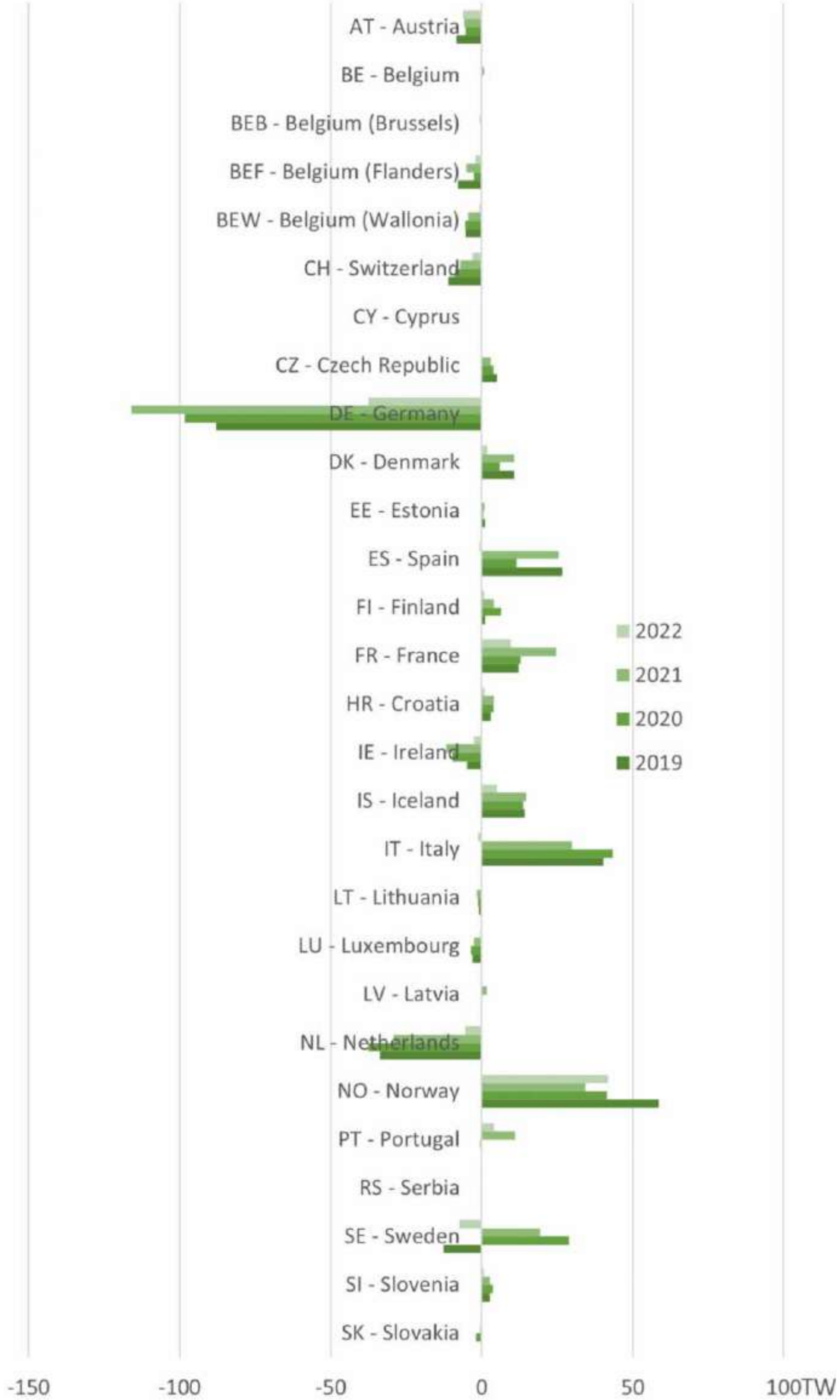

Figure 22: Net transfer of GOs from exporting countries (positive values) to importing countries (negative values). For 2022, only the month of January is included (AIB, 2022).

The AIB does not ensure full compatibility of national GO schemes. For example, in Sweden GOs are issued for onsite electricity use, meaning that the produced electricity is directly used onsite without being injected into the public grid. This is not compatible with the GO scheme in the Flanders region of Belgium, which therefore excludes the cancellation of Swedish GOs from its regional system (VREG,

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2018). Furthermore, the Swedish GOs are only considered partially complementary to the German GOs, given that the Nordic residual mix forms the basis of the scheme. In contrast, other Nordic countries use the national residual mix allowing for double-counting of renewable attributes (UBA, 2019).

Especially the case of the Swedish scheme for self-consumption shows how European GOs schemes almost exclusively apply to electricity production. GOs for heating and cooling imply the sale of heat from the generators to the consumer and therefore are only applicable for countries with significant district heating networks, such as Denmark, Sweden, Slovakia and the Baltic States (WEDISTRICT, 2020).

Under RED I, combined heat and power installations can obtain two different types of GOs, either for electricity or heat generation. Latter mentioned, are specified further in the Energy Efficiency Directive (2012/27/EC) and its predecessor, the Cogeneration Directive (2004/8/EC), but are to be aligned even further to GOs for energy sources with the revision of the Renewable Energy Directive (COM(2021) 557 final).

In general, the national framework specifying award criteria GOs for renewable or low-emission heat consumption differentiates between utilising residual off-heat and heat generation. If produced with fossil-fuelled CHP, heat generation is not renewable since resulting in direct fossil emissions. Off-heat, however, would be emitted if not used and is therefore considered to be emission neutral. Hence, some national regulations for GOs, for example, in the case of the Netherlands, explicitly exclude industrial CHPs and other heat generators.[15]

Other than GOs for off-heat or CHP installations using fossil energy carriers, biomass-based CHPs should be less prone to double counting since the primary energy source is not of fossil origin. Suppose biomass is used in combination with CHP. In that case, both electricity generation and heat generation should be eligible to GROs, since biomass use can result in net-zero emission energy production. A prerequisite for biomass to contribute to emission reductions and obtaining GROs is its sustainability, as analysed hereunder.

2.3.3 The role of biomass sustainability certification for GOs

The purpose of sustainability certification schemes is that biofuels, bioliquids and biomass fuels are sustainably produced by verifying that they comply with the EU sustainability criteria. GOs and sustainability certification schemes share common design elements but are intrinsically different. As summarised in Table vi, both are based on the Renewable Energy Directives. While the core document of GOs shall state the origin of an energy source regardless of its emission intensity, the sustainability certificates shall primarily serve as proof of origin. In order to obtain such certificate a detailed assessment of the production process, including the sustainability of land use, is required. As mentioned in section 1.2.8, the EU scheme is based on voluntary third-party verification, subject to recognition by the European Commission[16]. GOs and sustainability certification could potentially be

[15] See, WJZ/14198645 published on the 9th of December 2014

[16] The list of currently recognised schemes is available under:
https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/voluntary-schemes_en

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combined into a single certification scheme that complies to RED requirements for GO. Vertogas has implemented a scheme for biogas in the Netherlands, which is associated with the European Renewable Gas Registry (ERGAR). ERGAR has applied to be recognised as a new voluntary scheme by the European Commission.

Table vi. GOs versus sustainability certificates, as published by (Bjerg, 2019)

	Guarantees of origin (GO)	Sustainability certificate
Relevant articles of RED II	Article 19	Articles 25-30
Purpose	Disclosure of the origin of RES to end consumer. Independent from compliance with RED II sustainability requirements.	Proof of compliances with the RED II sustainability criteria, incl. GHG emission savings requirements.
Scope of applicability	To all renewable energy sources according to the definition of RES of Art.2, including biomass	Only to biofuels, bioliquids and biomass fuels, if compliant with the sustainability criteria of art. 29
Core document	Guarantees of Origin	Proof of Sustainability
Principle	Book & Claim	Mass balancing

2.3.4 Hydrogen and GOs

As explained in subsection 1.3.2, the technology being developed in this research project will be able to use hydrogen as a feedstock for fast-start capability, but it will also be able to produce renewable hydrogen, either through a process of water electrolysis driven by the electricity generated in the CHP topping cycle, or directly through the gasification of biomass and catalytic steam reforming. Such a plant, therefore, will be active in the hydrogen market both on the demand and the supply side and the same is true for the scheme that will be in place for the issuance and cancellation of guarantees of origin for decarbonised gas.

The global momentum on hydrogen as clean energy fuel has been extraordinary in the last few years. A large number of countries has developed hydrogen roadmaps or strategies, many pilot projects have been launched (sometimes in the framework of the so-called regulatory sandboxes) and the legislative activity on the topic starts being significant. However, it must be highlighted that, at this writing, it is very hard to make any prediction on how the hydrogen sector will look like in the medium and long term. For the time being, the use of hydrogen as an energy vector is almost inexistent. There are some regulatory aspects that have been broadly discussed, like how to classify hydrogen (green, blue, renewable, low-carbon, etc.) and how to design a scheme of guarantees of origin; but other aspects, as the design of the hydrogen market itself or the regulation of hydrogen networks, have been explored so far only in a superficial way. The Hydrogen and Decarbonised Gas Market Package of the European Commission, currently under proposal (EC, 2021b, c), recognise the need of regulatory flexibility and outlines a framework in which regulation will be developed together with the growth of the sector, allowing for exceptions and a larger degree of flexibility until 2030.

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This subsection focuses on the aspects that may be more relevant for a CHP plant that can both consume and produce hydrogen, i.e., the scheme of guarantees of origin and the potential design of the market.

2.3.4.1 Guarantees of origin

Guarantees of origin, or GOs, may be a central regulatory element for the deployment of the hydrogen industry, since they can be directly related to support schemes or international (or interregional) trades. From a theoretical point of view, guarantees or origin are an energy labelling scheme, which, through a tracking mechanism, can ensure the renewable or sustainable origin of some energy products (Velázquez Abad and Dodds, 2020). A labelling scheme is not the same as a certification scheme, which may issue certificates to be used, for instance, in a mechanism based on tradable quotas (as renewable portfolio standard in the United States, or green and white certificates in Europe). A labelling scheme has the only purpose to provide consumers with transparent information regarding the origin of a certain product and it is commonly based on thresholds, which define the eligibility for obtaining the GO. This label should allow the producer to sell the product at an above-the-market price, receiving a premium in the same market. On the other hand, quota systems require certificates that quantify exactly the parameter under study (e.g., emission reductions); certificates are sold together with the product, but their price is set in a separate market. This being said, it must be remarked that in this initial phase of the development of the hydrogen industry, GOs and certificates are being used as synonyms by some experts and there are proposals to use guarantees of origin in mechanisms based on tradable quotas (COAG, 2019).

A GO scheme allows the issuance, trade, and cancellation of guarantees assigned to a product or service that complies with certain criteria. When GOs are applied to hydrogen, these criteria are commonly related to the emission of greenhouse gases (GHG). Although other parameters, as the water consumption, may be included in the labelling, most hydrogen schemes are focused on the equivalent CO_2 emissions. For measuring the emissions of hydrogen production, a perimeter must be defined. Most GO scheme refer to scope-2 CO_2 emissions[17], as per the definitions recommended by IPCC (2014).

Once emissions are identified, the scheme require a threshold or a target level. These can be defined either as an absolute value or by requiring a certain percentage reduction with respect to the emissions of a reference technology. Some experts (Velázquez Abad and Dodds, 2020) expressed concerns regarding the definition of a single threshold, since it prompts project developers to select the cheapest (and not the cleanest) option to stay below the threshold.

Guarantees of origin also require a chain of custody that allows to track the origin of the product. Hydrogen GOs are commonly based on a book-and-claim chain of custody, which allows to completely decouple the physical product from its GO, which can be traded separately.

Although there are different initiatives to introduce a hydrogen GO scheme (for a review, see Piebalgs and Jones, 2020), the most advanced is certainly CertifHy, a project commissioned by the European

[17] In the case of hydrogen, scope-2 emissions would include CO_2 emissions generated during the production of hydrogen from other energy sources.

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Union and financed through the Fuel Cell and Hydrogen Joint Undertaking. CertifHy is a labelling scheme focusing on hydrogen CO_2 emissions, which are assessed based on a reference technological process, i.e., the steam reforming of natural gas. In the framework of this scheme, two labels are being proposed, one for green hydrogen and one for low-carbon hydrogen, depending on the energy source (Figure 23). Both products have to achieve a 60% reduction with respect to the reference technology (this corresponds approximately to 4 $kgCO_2eq/kgH_2$). Green hydrogen could be produced, for instance, through electricity generated from renewables or directly through biogas, while low-carbon hydrogen could be produced through electricity from nuclear power or through fossil fuels with carbon capture and storage.

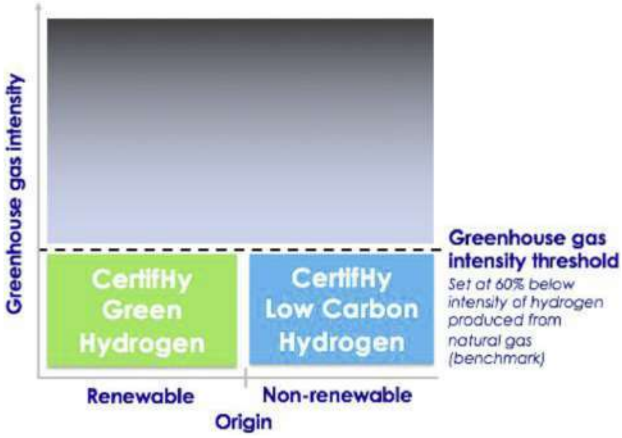

Figure 23. Labels proposed in the framework of the CertifHy (2020) project

CertifHy GOs are based on a book-and-claim approach, thus no control of the physical flow of hydrogen would be required (Figure 24). It must be remarked that, when a hydrogen production process uses multiple energy inputs, this will be reflected in the amount of labels of the two types that it receives. If electricity from the grid is used, a possible transfer of GOs from electrons to molecules may happen, with GOs for renewable electricity being cancelled to generate GOs for renewable hydrogen.

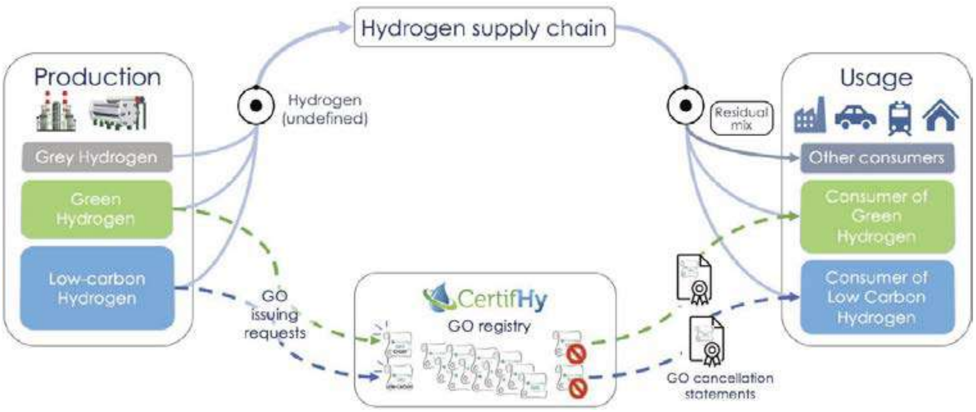

Figure 24. Operation of the CertifHy (2020) scheme

It must be remarked that the proposals for a Hydrogen and Decarbonised Gas Market Package (EC, 2021b, c) consider an emission reduction threshold equal to 70% for a gas to be considered low-carbon. This may be reflected in the GO scheme. Furthermore, these proposals try to avoid a duplication of the market premium that a project developer can receive, impeding the issuance of a

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GO if the hydrogen has already seen its emission reduction recognised and remunerated, for instance, in the EU ETS.

2.3.4.2 Hydrogen market design

Hydrogen already has a market nowadays, but this market is mainly related to the use of this element as a feedstock. Hydrogen as an energy vector will require a new market, whose design will probably vary in the different phases of the development of this industry. When the hydrogen sector will be fully developed, the obvious reference for its trade will probably be the gas market (Barnes, 2020). However, it is not clear now which market design will prevail during the transitional phase.

The decarbonisation of the gas sector may result in the appearance of several low-carbon gases, including hydrogen as well as a range of biogases of different origin. Actually, also within the hydrogen market, different products may be traded to fulfil different quality standards (e.g., hydrogen for fuel cells must be pure, while lower-quality hydrogen may be used in combustion applications). Another segmentation could stem from the labelling scheme, with some customers or end-uses preferring to procure, for instance, renewable hydrogen. In this context, markets for low-carbon gases may be very fragmented in the future, if compared with the current gas market. This may result in higher transaction costs, lower liquidity and increased market power.

In order to avoid these outcomes, there are proposals to maintain a unique gas market, which will integrate natural gas, hydrogen, and biogases, sending a common price signal. European gas network operators, for instance, outlined a gas market for the trade of non-homogenous products (Figure 25). The key element of such a market would be the energy content of the carrier, expressed in kWh, which would allow to maintain a high liquidity. Beside the market value of this energy content, other attributes would appear and be traded, as the sustainability of the carrier backed by guarantees of origin. These values need a technical layer to be traded, in which network operators would be in charge of either blending different gases or manage them in separation.

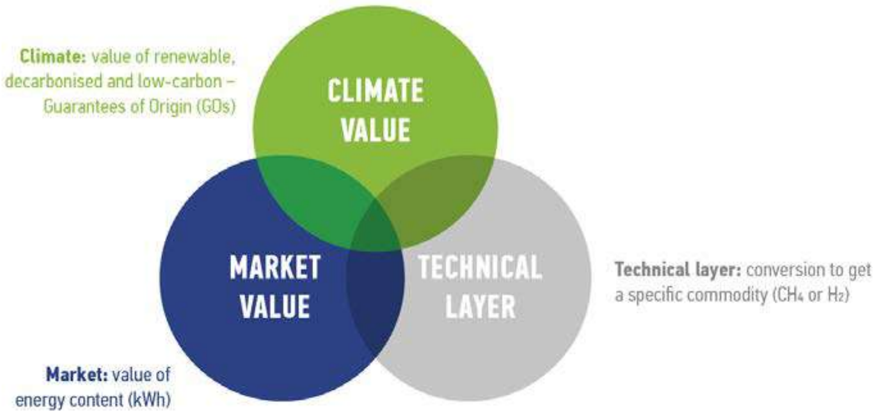

Figure 25. A gas market for non-homogenous products (ENTSOG, 2020)

When hydrogen demand and generation will be sufficiently developed and will start displacing the demand for natural gas, the sector could migrate towards a market model that would work solely for hydrogen. This market should include a liquid long-term segment, for the trade of contracts that would allow market agents to better hedge their risks.

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2.3.5 Support schemes

As already mentioned, combined heat and power is a technology that provides significant environmental benefits, but which is subject to technical complexities and usually has a relatively long payback period. For this reason, it has been provided economic support from many European Member States, especially after the publication of the so-called CHP Directive. A brief review of these support schemes was presented in subsection 1.2.3.1, while this subsection focuses on the main design alternatives for these mechanisms.

2.3.5.1 Target of the support

A CHP support scheme obviously target cogeneration, but the eligibility criteria may include several attributes that constrain the participation in the mechanism. The first evident discrimination is by size: several support schemes include a size threshold, commonly expressed in terms of installed capacity, below which the unit is not eligible for the economic aid. There is a trend to reduce or eliminate these minimum sizes. For instance, Germany has recently brought the threshold from 1 MW to 500 kW, in order to increase the pool of potential bidders and improve the competitiveness of auctions (EC, 2021b). Regulators can also impose upper thresholds. For instance, Spain is designing CHP auctions with a limit of 50 MW (MITECO, 2021). In other cases, the support may be different depending on the scale. In Slovakia, a CHP tender is organised for units with an installed capacity higher than 1 MW, while small-scale CHP units go through an administrative process that defines the economic support based on an estimation of their costs (EC, 2021c).

Some support schemes may also be oriented towards a specific final use of the heat or a certain energy source. For instance, specific schemes targeting CHP coupled to district heating and cooling have been introduced. As regards energy sources, the support may be limited to CHP driven by renewables, as biomass. Otherwise, it could explicitly prohibit the participation of a certain energy source, as it happens in Slovakia with coal (EC, 2021c). Other technological attributes may also be imposed. For instance, new cogeneration units willing to participate in the Spanish CHP auctions to be held in 2022/2024 will have to be able to use hydrogen as a fuel to cover at least 10% of its fuel demand and are expected to self-consume at least 30% of the electricity they produce (MITECO, 2021).

Finally, another potential targeting may take place through project-specific tenders. For instance, Poland has recently granted support to the construction of a high-efficiency CHP unit fuelled by biomass located in Chorzów (EC, 2020d).

When discussing about the target of CHP support schemes, it must be remarked that decarbonisation is the main goal and challenges for energy sectors nowadays; CHP contributes to decarbonisation through enhanced energy efficiency, but this contribution depends on the alternative technologies it is replacing. A recent study from the United Kingdom showed that a sustained increase of renewable and low-carbon generation decreases the emission reductions delivered by CHP electricity generation compared to the average grid emissions. Figure 26 shows the generation displaced in the United Kingdom by a 500-MW annual increase in the CHP installed capacity from 2018 to 2025, which includes, from 2025 onwards, also renewable sources. This analysis suggests that plants installed up until 2023 will deliver net carbon savings over their lifetime, but those deployed later would not.

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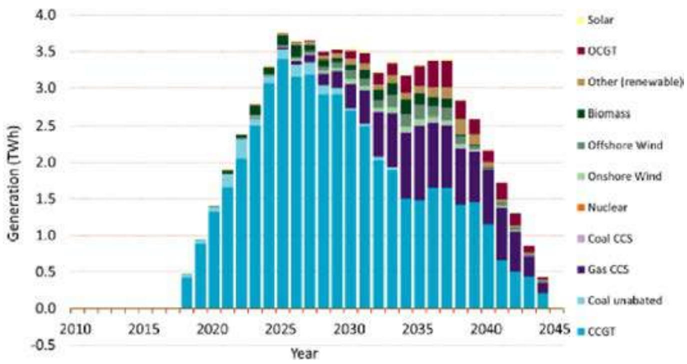

Figure 26. Generation displaced by a CHP penetration of 500 MW per year in Great Britain (BEIS, 2021b)

In order to avoid this undesirable outcome, the British Government is considering the possibility of ending support for new unabated gas CHP installations in the short to medium term. This discussion is likely to take place elsewhere in Europe, especially in those countries with higher penetration of renewable energy sources.

2.3.5.2 Type of support

As already analysed in subsection 1.2.3.1, there are several types of support that can be provided to CHP. The main distinction is between financial and fiscal support. The latter involves fiscal benefits that may encompass a variety of taxes and levies. For instance, the British CHP Quality Assurance programme (CHPQA) assesses the energy efficiency and environmental performance of all types and sizes of CHP schemes against the CHPQA Standard to determine whether they meet the criteria for 'Good Quality CHP' certification (BEIS, 2021b). This certification allows units to obtain operational incentives as i) beneficial treatment under climate change levy (CCL) and fuel duty; ii) beneficial treatment under the carbon price support (CPS) rates of tax; and iii) exemption from Business Rates of Power Generating Plant and Machinery.

On the other hand, financial support provides direct economic aid to project developers, either through grants on investment or operational aids, as feed-in tariffs and feed-in premia on the electricity production. Some schemes, as the German one (EC, 2021b), also consider specific aid for the installation of thermal storage, either for heating or cooling, in CHP facilities.

2.3.5.3 Risk management and exposure to market signals

As analysed in subsection 1.2.6, CHP is expected to contribute to the flexibility of the power sector. For this to happen, support schemes should reduce the risk perceived by investors, but maintaining the exposition to market signals that can allow an efficient operation of the facility. Feed-in tariffs, but also feed-in premia, may reduce or eliminate the incentive to produce during periods in which the electricity system is under stress.

CHP support schemes are being redesigned to allow a more efficient exposure to market signals. For instance, the reformed German scheme considers a feed-in premium on the electricity market price, but the number of operating hours eligible for support was reduced to further incentivise CHP units to produce electricity when it is needed the most, i.e., at times of higher electricity demand. Furthermore,

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electricity production during hours with negative prices is not only non-eligible for support, but it actually reduces the total amount of support that the unit can obtain (EC, 2021b).

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3 Case studies on barriers/challenges for CHP integration

3.1 Sweden

3.1.1 Country context

Cogeneration and nuclear power, together with large parts of hydropower, are today basic power in the Swedish electricity supply. Today, approximately 9% of the electricity produced in Sweden comes from CHP plants. There is great potential for expansion of CHP in Sweden as a weather-independent energy technology, which would improve the supply of base power. This is important as electricity production from nuclear power has decreased between 2019 and 2021. Over 90% of the fuels in Swedish CHPs are renewable or recycled. The most common is biofuel, which includes residues from forestry, such as stumps and branches. It can also be residues from households or industries, i.e., waste that has not been recycled in any other way. Some combined heat and power plants can even be operated entirely with residual heat from a nearby industry (Energiförtagen, 2022). Almost 13 TWh of electricity was produced by CHP in 2020 in Sweden. Electricity production with different technologies in 2021 is shown in Figure 27 (Energiförtagen, 2022). In 2021, other thermal power, mainly cogeneration in industry, increased by 17% to 14.9 TWh (almost 9% of total electricity production. Capacity of electricity production for different technologies is presented in Figure 28 (Energimyndigheten, 2022). The total production capacity of CHP was 4 400 MW in 2020.

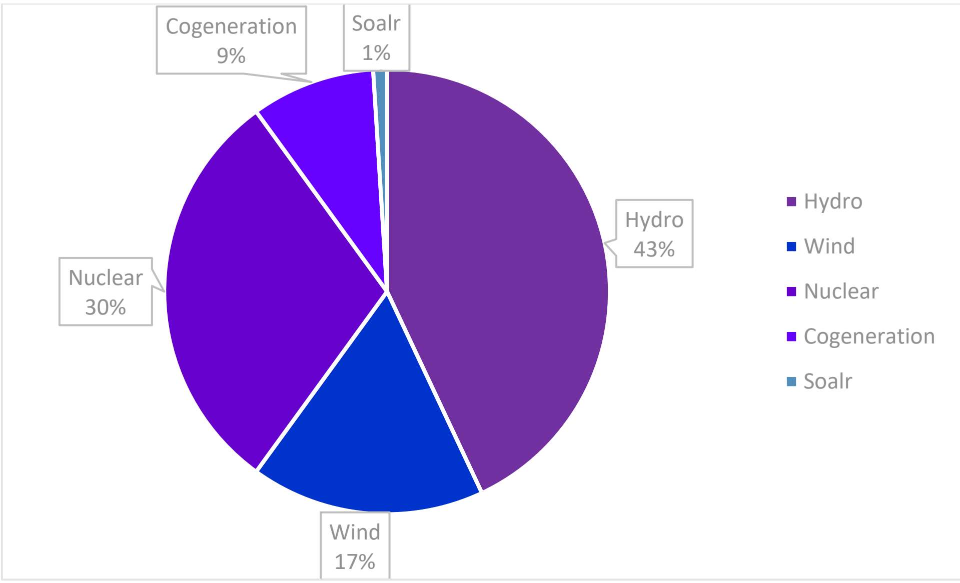

Figure 27. Electricity production in 2021 in Sweden (Energiförtagen, 2022)

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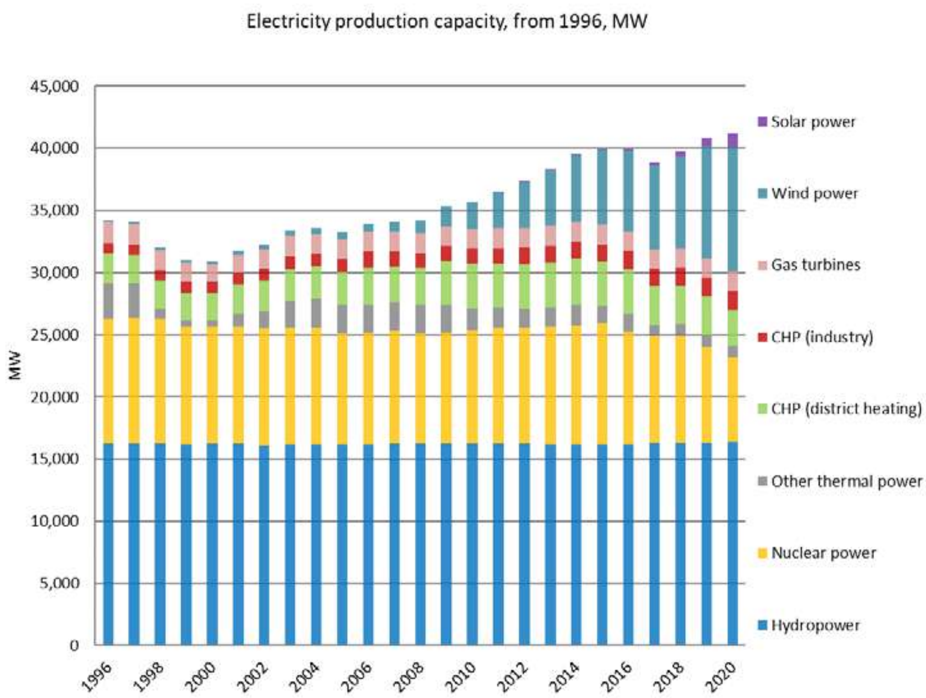

Figure 28. Electricity production capacity in Sweden (Energimyndigheten, 2022)

3.1.2 Regulatory context

The transition to a production mix based on renewable intermittent generation will create a larger need for grid services including frequency-regulation services. The European, Nordic and Swedish electricity and grid service markets will undergo large changes in the coming years. In the day-ahead market, the flow-based capacity allocation method will substitute the current net transmission capacity method. Intraday auctions will be introduced to complement the current continuous intraday market. The settlement period will change from 1 hour to 15 minutes (Svenska kraftnät, 2021). A new Nordic balancing model will be introduced and entail many changes to the current Nordic balancing setup (Nordic balancing model, 2021).

CHP plants are all equipped with synchronous generators which means that they contribute to the system inertia. CHP production based on biofuel is a well-tested technology which has been commercially available for a long time. Technology development is now mainly aimed at ever higher efficiency in Sweden. There are also demonstration projects for small-scale CHP using, for example, Organic Rankine Cycle technology working with lower temperatures. In Sweden, the fuel used is usually biofuel or to a lesser extent, waste. Biofuel-fired plants are more flexible and have a higher electrical efficiency than waste-fired ones. They are therefore able to deliver, and ultimately sell, system services such as balancing and peak load solutions. Waste-fired CHP plants have in general higher capital costs and lower electrical efficiency than biofuel-fired plants. Factors to take into account for investment are electricity prices, expected energy certificate price trends, fuel prices and anticipated annual operating times. The latter is an increasingly important issue as more and more weather-dependent power enters the system. New EU rules may impact biomass extraction from forests and also waste imports for waste CHP plants. The production of cogeneration depends on the heat demand of district heating. Reduction in heat demand not only affects the heat production but also electricity production.

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CHP plants in district heating systems could have a higher electricity price than the spot price because electricity is produced during the winter months when there is a demand for heat and the electricity price is in general higher (Byman, 2016).

The share of CHP in heat and electricity production has been increased from 1983 to 2020 based on report by Swedish Energy Agency (Swedish Energy Agency, 2022). Figure 29 shows that 41% of district heat use was produced by CHP, 10% of electricity sector.

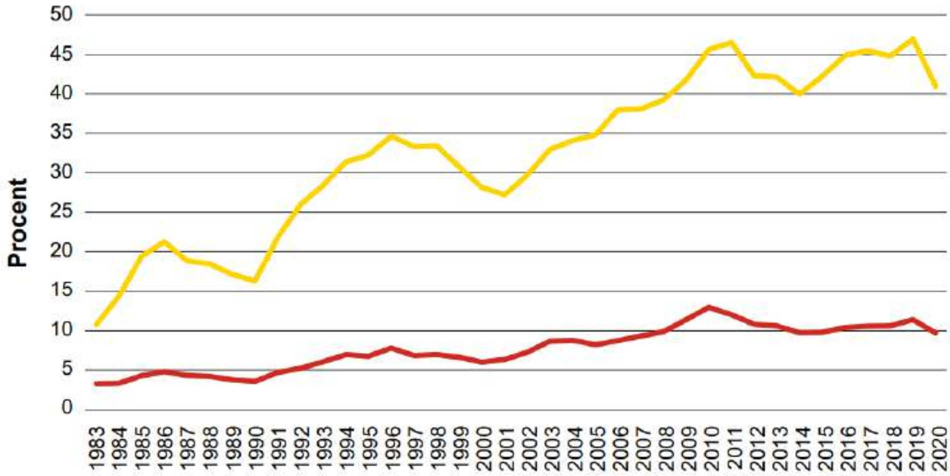

Figure 29. Electricity (blue curve) and heat (red curve) production in CHP plants in relation to the country's total electricity and district heating use including losses from 1983 to 2020 (Swedish Energy Agency, 2022)

Figure 30 shows the electricity certificated production in CHP between 2003 and 2011. 1 MWh is equivalent to 1 certificate. Between 2003-2010, Ca. 72.5 million electric certificates have been issued to CHP producers and sold to trading companies.

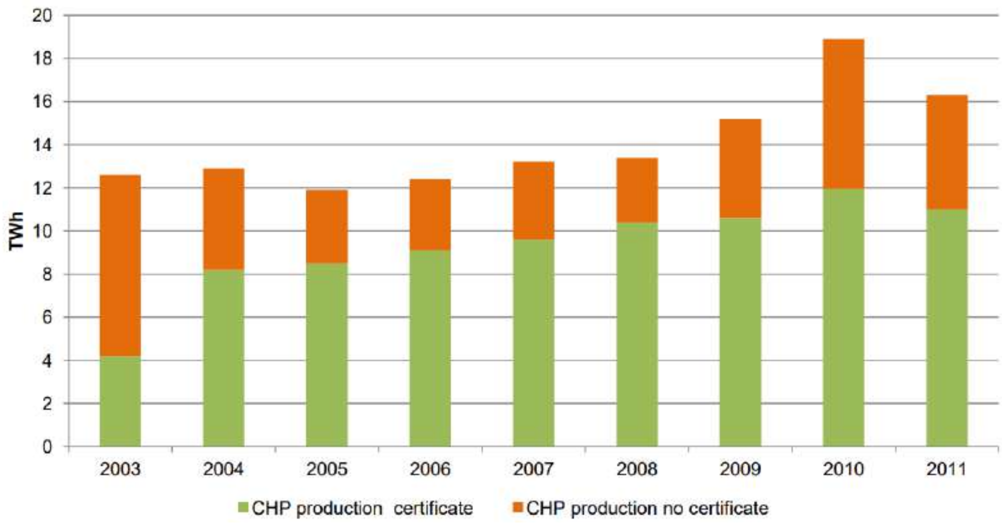

Figure 30. Electricity certificate production in CHP (Swedish Energy Agency, 2013)

A study about share of CHP in the total net cumulative fossil fuel based thermal plants capacity by (European Environment Agency (Ricardo-AEA), 2015) shows that in the period between 2020 and

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2030, more than 95% of the Swedish investment in fossil thermal power plants will be dedicated to CHP plants. They concluded that the majority of thermal power plants that will be built in Sweden likely to be CHP until 2030.

Taxation and subsidies have promoted renewables and CHP-development in Sweden. Policies of CO2 tax and introduction of investment subsidies to biomass and cogeneration plants in 1991 resulted in ca. 20 biomass fuelled CHP plants (Swedish Energy Agency, 2013). Also in 2003, the effect of the introduction of the electricity certificate system that led to an expansion of electricity and heat from bio-cogeneration (Swedish Energy Agency, 2022). CHP and all electricity producers are guaranteed access to the grid. There is no “trade off” or “crowding out” between renewable and CHP electricity production concerning access to the grid. The Swedish TSO (Svenska Kraftnät) is responsible for transmitting electricity from the major power stations to the regional electrical grids, via the national electrical grid. Availability of district heating network, favourable taxes, and high electricity prices are incentives of Swedish policy for CHP/DH (Swedish Energy Agency, 2013).

Industrial CHP plants don’t have carbon tax and they pay only 30% of energy tax. Heat produced in CHP plants pays both carbon dioxide tax, energy tax and emission allowances for its production (electricity production only pays for its emission allowances). As of 1 August 2019, the carbon dioxide tax was increased from 11% to 91% of the general tax level for fossil heat production in stand-alone CHP plants. At the same time, the energy tax was increased from 30 to 100% of the general level of energy taxation. However, the increase does not apply to industrial cogeneration (Swedish Energy Agency, 2022).

The additional potential for electricity production form CHP has approximately an increase from 10.5 TWh in 2011 to 15 TWh by 2030 (Ministry of Environment and Energy, 2018). This is estimated based on assumption that heat supplies from district heating will decrease slightly in long term. The overall assessment for the potential of industrial CHP plants is 8.8 TWh by 2030. This was 6 TWh per year until 2018.

3.1.3 Participation in the electricity market

3.1.3.1 Day-ahead market

Trading on the day-ahead and intraday markets is done via a Nominated Electricity Market Operator (NEMO), to which market participants send production and consumption bids. There are three NEMOs in Sweden: Nord Pool, EPEX and Nasdaq. Most of the trading is done via Nord Pool. Some historical volumes and prices on these markets are available on Nord Pool’s website (Nord Pool, 2022).

The day-ahead (DA) spot market is a marketplace where a competitive auction takes place based on which the next day price is calculated. The day-ahead electricity market is operated in three steps: 1) bidding, 2) market clearing and 3) pricing. At step 1 all market players (producers and consumers) submit their production or consumption bids in the respective price area before the gate closure. Bids can be single or block bids. The pricing is based on marginal pricing.

The gate closure time is at 12:00 CET D-1, i.e., the day before the operation. After the day-ahead market gate closure, at step 2, the single day-ahead coupling (SDAC) is run, meet the demand with the least possible cost. SDAC is a pan-European algorithm. Alternatively, two different curves are constructed while aggregating all purchase and supply bids. The intersection of these curves defines the trade volume for every hour. This step results in production and consumption commitments for

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the market actors whose bids have been accepted. Deviations from these day-ahead commitments can be traded on the intraday market or settled in the imbalance settlement process. At step 3, the market clearing prices in each bidding zone are computed based on the accepted bids in step 2. The full description of the algorithm is given in (NEMO Committee, 2020). The results are publicly released at 12:42 CET. In the case of transmission congestion, the bidding zones will have different prices.

3.1.3.2 Intra-day market

The intraday (ID) market is a continuous market that opens at 14:00 CET D-1 and closes 1 h before the actual delivery hour in Sweden (NordPool, 2021). Intraday markets aim to decrease the imbalances occurring between day-ahead and real-time markets (Nord Pool, 2022), which can help reduce imbalance costs for producers or consumers whose day-ahead bids are based on forecasts. For district heating systems, changes to day-ahead forecasts may include changes in temperature forecasts or unit availability.

The volume traded in intraday markets is not big compared with that of day-ahead and real-time markets. However, the utilization of the intraday market is increasing parallel with the increase of renewable energy sources, namely intermittent wind and solar power, (Nyström, Hamon, & Brolin, 2021).

Intraday trading is done through the pan-European Single Intraday Coupling (SIDC) (ENTSO-E, 2021), enabling intraday trading in 23 European countries. Bids can be sent continuously between the gate opening time and the gate closure time. Bids are matched pairwise as soon as a possible match is found. The prices for this market are set on a pay-as-bid basis.

3.1.3.3 Review of ancillary service markets

One of the main responsibilities of the TSOs is to maintain the balance between production and consumption during operations. This can be provided by running ancillary service markets for balancing purposes. The different ancillary service markets have different requirements in terms of, e.g., activation times and endurance, and therefore complement each other to cover the required balancing needs within the hour.

The current ancillary services used for balancing purposes in Sweden are listed in Table vii (with the exception of the disturbance reserves and strategic reserves). Table vii gives an overview of the ancillary services presented in the following and they are illustrated in Figure 31 in terms of activation following a frequency drop. The overview of the ancillary services with their purposes are introduced in the following.

Table vii. Overview table of requirements of ancillary services (Svenska kraftnät, 2022)

FFR	FCR-N	FCR-D up	FCR-D down	aFRR	mFRR(manual)
Fast frequency reserves	Frequency containment reserves for normal operation	Frequency containment reserves for disturbances	Frequency containment reserves for disturbances	Automatic frequency restoration reserves	Manual frequency restoration reserves (“regulating market”)

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FFR	FCR-N	FCR-D up	FCR-D down	aFRR	mFRR(manual)
Up-regulation	Symmetric	Up-regulation	Down-regulation	Separate products for up- and down-regulation	Separate products for up- and down-regulation
Minimum bid size: 0.1 MW **Activation:** Automatic for frequency changes at low levels of rotational energy.	**Minimum bid size:** 0.1 MW **Activation:** Automatically in case of frequency deviation within 49.90 – 50.10 Hz	**Minimum bid size:** 0.1 MW **Activation:** Automatically in case of frequency deviation within 49.9 – 49.50 Hz	**Minimum bid size:** 0.1 MW **Activation:** Automatic linear activation in the frequency range of 50.1 – 50.5 Hz	**Minimum bid size:** 5 MW **Activation:** Automatically through a central control signal if the frequency deviates from 50.00 Hz.	**Minimum bid size:** 10 MW (5 MW in SE4) **Activation:** Manually at the request of Svenska kraftnät
Activation time: 3 alternatives for 100%: - 0.7 second at 49.5 Hz - 1 second at 49.6 Hz - 1.3 second at 49.7 Hz	**Activation time:** 63% within 60 sec. and 100 % within 3 min.	**Activation time:** 50% within 5 sec. and 100% within 30 sec.	**Activation time:** 50% within 5 sec. and 100% within 30 sec.	**Activation time:** 100 % within 120 sec.	**Activation time:** 100% within 15 min
Volume requirement: approx. 100 MW for Sweden	**Volume requirement:** approx. 240 MW for Sweden	**Volume requirement:** approx. 580 MW for Sweden	**Volume requirement:** approx. 560 MW for Sweden	**Volume requirement:** approx. 150 MW in Sweden	**Volume requirement:** No volume requirement
Endurance: Endurance: 30 sec. alternative 5 sec. Repeatability: ready for action within 15 minutes	**Endurance:** Endurance: 1 hour.	**Endurance:** Endurance: at least 20 minutes	**Endurance:** Endurance: at least 20 minutes	**Endurance:** Endurance: 1 hour.	**Endurance:** Endurance: 1 hour.
Capacity compensation Marginal pricing	**Capacity compensation** Pay-as-bid. Will change to marginal pricing in 2024.	**Capacity compensation** Pay-as-bid. Will change to marginal pricing in 2024.	**Capacity compensation** Pay-as-bid. Will change to marginal pricing in 2024.	**Capacity compensation** Pay-as-bid. Will change to marginal pricing during 2022.	**Capacity compensation** None.

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FFR	FCR-N	FCR-D up	FCR-D down	aFRR	mFRR(manual)
Energy compensation None.	**Energy compensation** According to up/down regulation prices.	**Energy compensation** None.	**Energy compensation** None.	**Energy compensation** According to up/down regulation prices.	**Energy compensation** According to up/down regulation prices.
Gate closure time Two weekly procurements: Mondays for Tuesday to Friday Fridays for Saturday to Monday	**Gate closure time** Two procurements: 16:00 D-2 and 18:00 D-1. Will change to two procurements at D-1 in Q2 2022	**Gate closure time** Two procurements: 16:00 D-2 and 18:00 D-1. Will change to two procurements at D-1 in Q2 2022	**Gate closure time** Two procurements: 16:00 D-2 and 18:00 D-1. Will change to two procurements at D-1 in Q2 2022	**Gate closure time** One weekly procurement on Thursdays. Will change to daily D-1 procurements during 2022.	**Gate closure time** 45 minutes before the delivery hour.

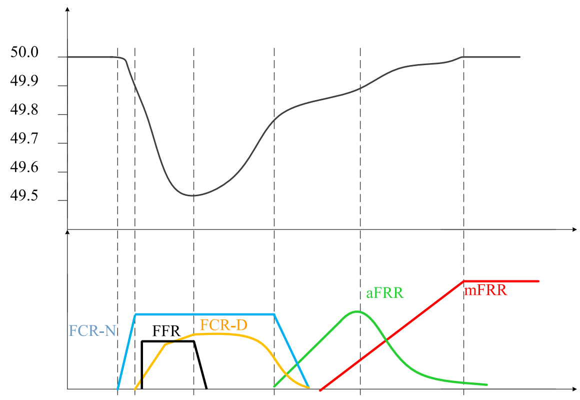

Figure 31. Activation of the different ancillary services in Sweden.

Fast Frequency Reserves (FFR)

Purpose: Automatically activated service that handles the initial rapid and deep (transient) frequency deviations that can occur in the case of low-level rotational energy errors in the Nordic power system.

Larger amounts of converter-based generation have increased the occurrence of low-inertia events in the Nordic system. Meanwhile, the existing reserve products were not fast enough to react to these low-inertia situations. To overcome this issue, the Nordic TSOs have launched FFR products in June 1, 2020 (ENSTO-E, 2019).

FFR providing units should pass a prequalification test to participate in the FFR markets. The pre-qualification process ensures fulfilment of technical requirements, so that FFR providers can deliver FFR as required by the TSO. The FFR volume is quantified in MW. FFR is intended to be a fast, active power support, responding to a frequency deviation.

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Frequency Containment Reserve (FCR)

Purpose: Automatically activated services that stabilizes the frequency in case of small changes in consumption or production. It is symmetrical.

FCR are products activated automatically in the time frame of seconds to minutes by local frequency measurement. **FCR-Normal (FCR-N)** and **FCR-Disturbance (FCR-D)** products are considered as operating reserves, which contain the deviation of the frequency from the nominal value.

For both products, procurement is done 1 and 2 days ahead of the hour of delivery: the first gate closure is at 15:00 CET D-2 and the second one is at 18:00 CET D-1. The second market acts as a complement to the first one if the reserves procured on the first market D-2 are deemed insufficient. Offers for any of the 24 hours of day D must be submitted either before the first gate closure or the second gate closure. The procurement is settled by Svenska kraftnät. The pricing is pay-as-bid. Svenska kraftnät publishes the average prices on Mimer (Svenska kraftnät (Mimer), 2021) in the early morning of the day of delivery.

Frequency Restoration Reserves (FRR)

We distinguish two types of frequency restoration reserves: **automatic (aFRR)** and **manual (mFRR)**. aFRR has a faster response than mFRR. The aFRR product is an automatic complement to mFRR in the FRR process. Moreover, the aFRR reserve differs from FCR products: the aFRR reserve is centrally controlled remotely, while FCR is locally controlled.

- Automatic Frequency Restoration Reserves (aFRR)

Purpose: Automatically activated service which restores the frequency to 50 Hz. Separate products for up- and down-regulation.

The aFRR product was introduced in the Nordics in 2013. The product was introduced to tackle the deteriorating problem related to the frequency quality. The aFRR product was recognized as one of the main counter measures. As it was mentioned above the aFRR differs from the FCR products the way it is controlled. Besides, there is also a difference in activation time and in the role these two market products have. FCR aims at stabilizing the frequency while aFRR brings the frequency back to its nominal value. Thus, the time when aFRR is active, there is an interaction between FCR and aFRR.

- Manual Frequency Restoration Reserves (mFRR)

Purpose: Manually activated service which relieves the automatic services and restores the frequency to 50 Hz. Separate products for up- and down-regulation.

Manual Frequency Restoration Reserves (mFRR) aims at providing replacement of the remaining frequency deviation after FCR and aFRR reserves are applied. mFRR ensures that the frequency is at the nominal value in the long run. As the aFRR volume is limited and congestions in the grid are potentially possible, the Nordic system is highly dependent on mFRR. Thus, mFRR provides the main balancing resource in the system ensuring system stability and security (Entsoe, 2021). The mFRR market is sometimes called the regulating market.

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Disturbance reserves

In addition to the voluntary energy-only mFRR market, Svenska kraftnät has agreements with gas turbines in SE3 and SE4 for a total capacity of 1350 MW, which is the dimensioning fault in Southern Sweden. These reserves are called disturbance reserves (Svenska kraftnät, 2021). When gas turbines are out of operation due to maintenance, Svenska kraftnät reduces the trading capacity between SE2 and SE3 and between SE3 and SE4, in order to reserve capacity for transferring mFRR energy from the North (where there usually is enough mFRR capacity on the voluntary market) to the South. The disturbance reserve is activated only if all mFRR bids in the energy-only market have been activated, is considered special regulation and therefore priced pay-as-bid.

Winter strategic reserves

Svenska kraftnät has procured strategic reserved up to 2025 with Sydkraft Thermal Power AB for a total of 562 MW from Karlhamnsverket (Svenska kraftnät, 2019). The EU Clean Energy Package sets a framework for the procurement of strategic reserves. In particular, countries can only procure strategic reserves if there is a defined target for resource adequacy as well as a defined method to evaluate resource adequacy. The current procurement framework is not in line with the EU Clean Energy Package and will be terminated in 2025. Up until 2025, Svenska kraftnät is not allowed to perform new procurements for the strategic reserves. Therefore, there is no opportunity for new actors to start contributing to the strategic reserves.

Winter strategic reserves are used in periods when production adequacy is constrained or insufficient and should be available between 16 November and 15 March. This typically occurs during the winter.

3.1.4 Participation in the heating market

District heating companies are particularly well-fitted for participating in the electricity markets thanks to their geographical location close to the electric consumption centres in the cities. Swedish district heating companies set their billing prices freely considering different cost factors, including costs for alternative technologies to which consumers could switch.

The flexibility in district heating systems that can be used in the electricity sector can take many forms: changes in the electricity production / consumption of heat production units, by-product usage of the excess heat (e.g. fuel drying), thermal storage in water tanks or other kinds of storage facilities, thermal storage in the pipeline network and thermal storage at the customers' site (for example in buildings). Research on the technical capabilities shows that many units in the district heating systems can fulfil the requirements for delivering ancillary services. Many research works have identified possible economical gains from participating in more segments of the electricity market (for example ancillary service markets). However, many research works in this field have focused on single CHP plants instead of considering the whole portfolio of units in the district heating systems.

District heating can play key roles in meeting the challenges associated with the energy transition. First, the massive electrification will lead to additional local grid and production capacity challenges where the existing electric grids do not have enough capacity to transfer the required amount of electricity. This is already happening in several Swedish metropolitan areas (Energimarknadsinspektionen, 2020) and can have large consequences on employment, housing, infrastructure and economic growth (Stockholms handelskammare, 2020). In this respect, district heating systems can remedy the issue by both decreasing the need for electricity for heating and

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providing local electricity generation in CHP plants. Furthermore, sector coupling units in district heating systems such as CHP plants, heat pumps and electric boilers can contribute with flexibility in heat and local electricity networks (Energiföretagen, 2020). Therefore, there is a need to investigate how further integration of district heating systems with the electrical grids and markets will impact operation and planning of such systems.

Yearly, the Swedish heat market including district heating and other technologies produces 100 TWh heat, half of which comes from district heating as shown in Table viii (Energimyndigheten, 2021). District heating systems in Sweden enable utilisation of energy resources that would otherwise be wasted. This relates to the waste heat from industry and energy from the recycling of waste (EnergyFöretagen, 2021). Figure 32 shows the shares of fuels and sources for heat production in Sweden in 2020.

Table viii. Statistics of district heating in Sweden (Energimyndigheten, 2021)

District heating consumption (year 2019)	Share of space heating demand supplied by DH (year 2019)	Electricity production from CHP plants in DH (year 2019)	Share of yearly national electricity consumption covered by CHP plants
56.3 TWh	Ca 50%	9 TWh	6.5%

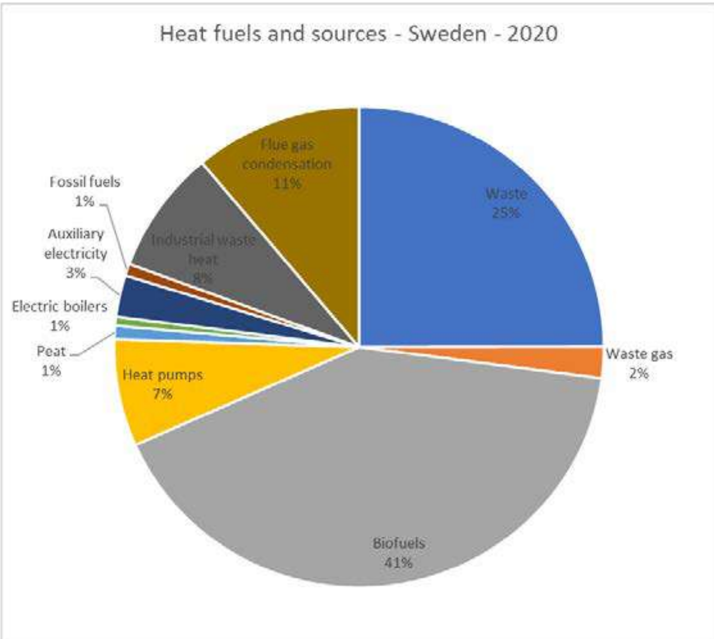

Figure 32. Heat fuels and sources in Sweden for 2020. Source: (Energiföretagen, 2021)

The pricing on the heat market in Sweden is not regulated. Customers are free to choose their preferred heat solutions among district heating and other competing technologies such as direct electricity, heat pumps, pellet boilers etc. The district heating companies have a dialogue with the major customers and explain and motivate the heat price to keep their customers as they act on a non-

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regulated market. There is currently no common pool to trade heat in Sweden. The heat market is always local, and heat cannot be traded between separate cities except in a few cases where district companies in neighbouring communes share the same heat network.

Prices are system dependent. In 2021, the average district heating price, including VAT, was 94 EUR/MWh for single-family detached houses, 86.7 EUR/MWh for smaller multifamily residential and 86.8 EUR/MWh for larger multifamily residential. The full distribution of district heating prices for these different housing categories is shown in Figure 33.

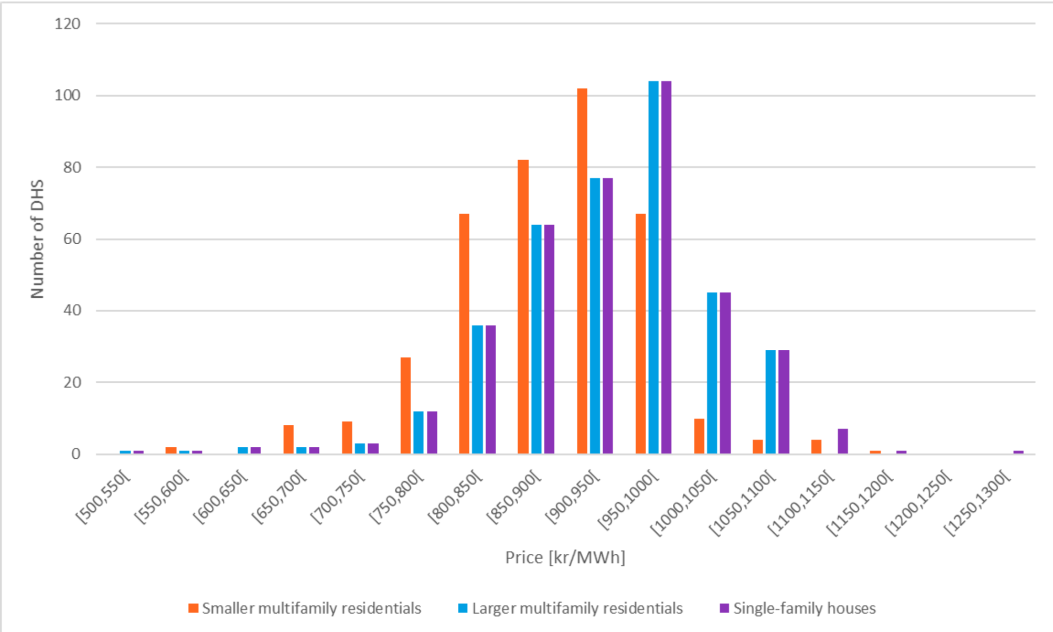

Figure 33. Distribution of the district heating prices in 2021 (number of district heating systems having a certain price, including VAT), numbers from (Energiföretagen, 2021).

There are basically two pricing experiences related to Swedish district heating system:

1. Cost based and
2. Market based

Most municipality-owned companies (the majority of district heating companies) apply the first option. Price levels are set in order to cover all the costs, including required yield to the owners. However, the heat suppliers also take into account the customers cost from an alternative type of heating.

Many private owned companies and a few municipals owned apply the second option while formulating the price. The suppliers under this category consider investment costs, future electricity prices, interest rates etc., and set the price at levels that are still competitive with other suppliers. In addition, like for municipal companies, they analyse the alternative for the major customers, for example the cost of heat pumps.

Besides these basics, different district heating companies apply a wide variety of price models. Locally, the individual district heating company can also have two or several price models for different categories of customers.

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Recent research has focused on designing local energy markets that integrate several energy carriers such as heating, cooling and electricity. For example, a local market for electricity, heat and cooling has been created in the Chalmers area in Gothenburg in the FED (Fossil free Energy District) project (Brolin & Pihl, 2020), (FED – Fossil-free Energy Districts, 2019). A demo was run with more than 50 buildings and production units in that area.

To participate in an ancillary service market to provide flexibility, power generation plants are expected to have the technical requirements from "Svenska Kraftnät" in Sweden and the specific tender conditions. However, not all CHP plants have the technical possibilities and requirements. Currently, DH companies in Sweden are very interested in results of those projects which aim at investigating the optimal design and technical capabilities of CHP plants enabling them to provide ancillary service markets.

3.2 Spain

3.2.1 Country context

Spain has a large CHP fleet of 5 700 GW, which accounts for 12% of the electricity production in the country (CNMC, 2021a). As it can be observed in Figure 34, the vast majority of the CHP units were installed between 1990 and 2002, with only minor additions and decommissions since then. Most of Spanish CHP power plants are driven by natural gas.

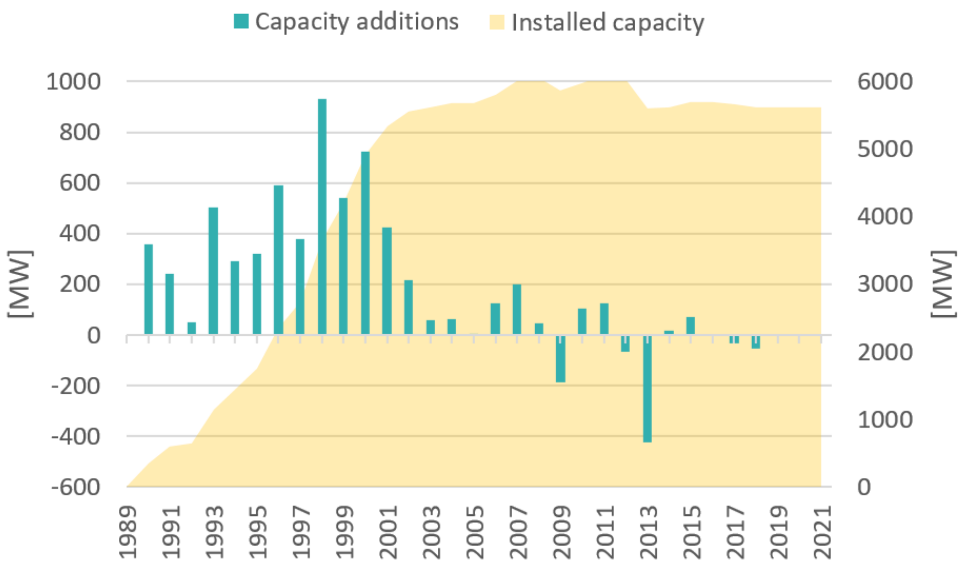

Figure 34. CHP installed capacity in Spain and yearly capacity additions; data from CNMC (2021a)

The last comprehensive study on the Spanish CHP sector is from 2010 (Acogen, 2010), but it still represents the reality of the industry. Figure 35 shows the capacity range of Spanish CHP. The 1-10 MW range is the most common one and 97% of the fleet has an installed capacity below 50 MW.

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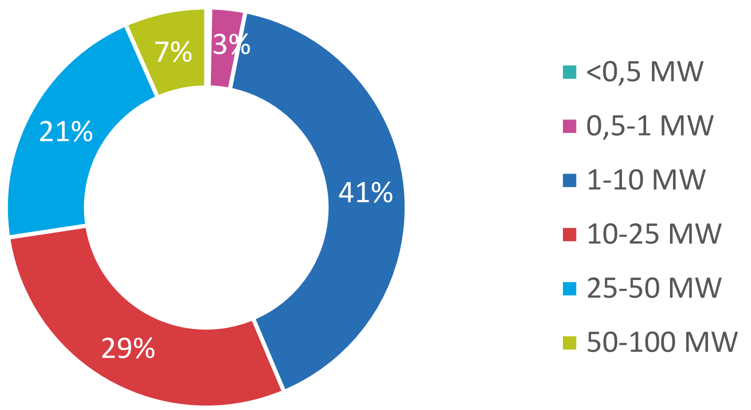

Figure 35. Installed capacity range of Spanish CHP units; data from Acogen (2010)

Almost 90% of the CHP fleet serves the industrial sector, while the remaining 10% is used in the commercial and residential sectors, mainly in heat networks. Within the industrial sector, Agriculture and food processing, paper and printing, and the chemical industry cover the largest shares (Figure 36).

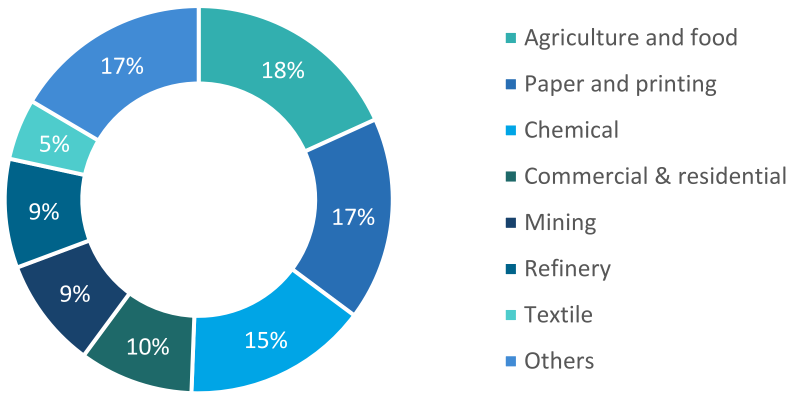

Figure 36. Final use of Spanish CHP by sector; data from Acogen (2010)

The CHP fleet is quite evenly distributed in the Spanish geography, with a concentration slightly higher in the coastal regions (Figure 37). The industrial intensity of the region is clearly one of the drivers of the CHP installed capacity.

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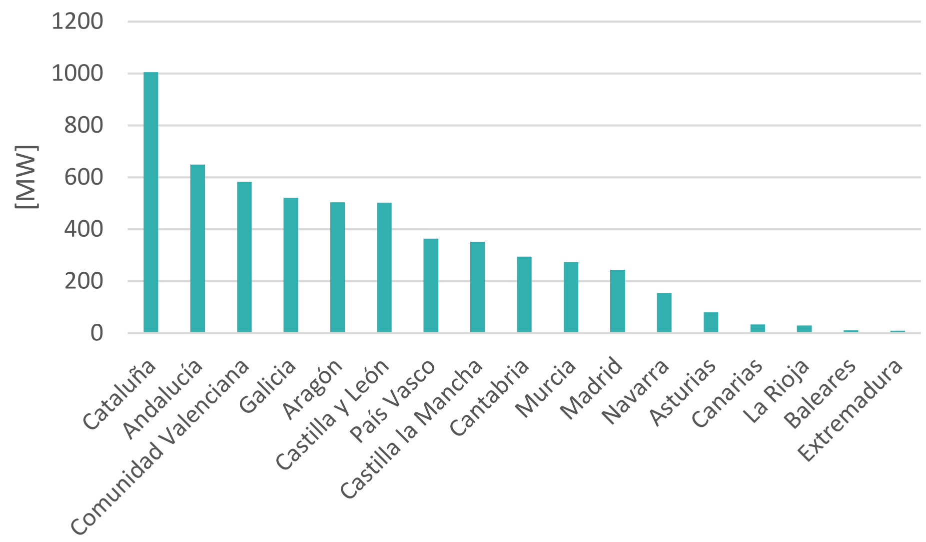

Figure 37. Distribution of the Spanish CHP fleet in the national territory; data from Acogen (2010)

3.2.2 Regulatory context

As shown in Figure 34, most of the Spanish CHP capacity was installed in the 1990s, before the liberalisation of the power sector, under the regulatory framework defined by the Royal Decree 2366/1994, which introduced a "specific supply regime" for renewable energy sources and high-efficiency cogeneration, with guaranteed access to the network and regulated tariffs for the electricity injections.

After the liberalisation, the specific regime was reformed through the Royal Decree 2818/1998, which introduced tariff reviews and increased the uncertainty perceived by project developers. Capacity additions have significantly slowed down since then, while some of the first units to be installed have already been decommissioned. The support scheme was reformed once again through the Royal Decree 413/2014, with the definition of the formulas still in use to calculate a feed-in premium that is paid on the top of the wholesale market price.

According to the national association of cogeneration plants, half of the fleet, almost 3 GW of power, will have to take a decision on the continuity of the CHP unit before 2025. The Spanish National Energy & Climate Plan (NECP) does not provide an optimistic view for the cogeneration sector (MITECO, 2020). The NECP recognises that many CHP units will reach the end of their useful life and will be decommissioned. In the reference scenario, CHP installed capacity falls to 2 470 MW, from the almost 6 000 MW today. The Spanish Government is apparently not willing to prompt a plan that would bring CHP to grow in the country, but it is willing to reduce this plunge in the installed capacity by means of specific auctions, to be held between 2022 and 2024, which are supposed to bring 1 200 MW of new CHP capacity by 2027 (Figure 38).

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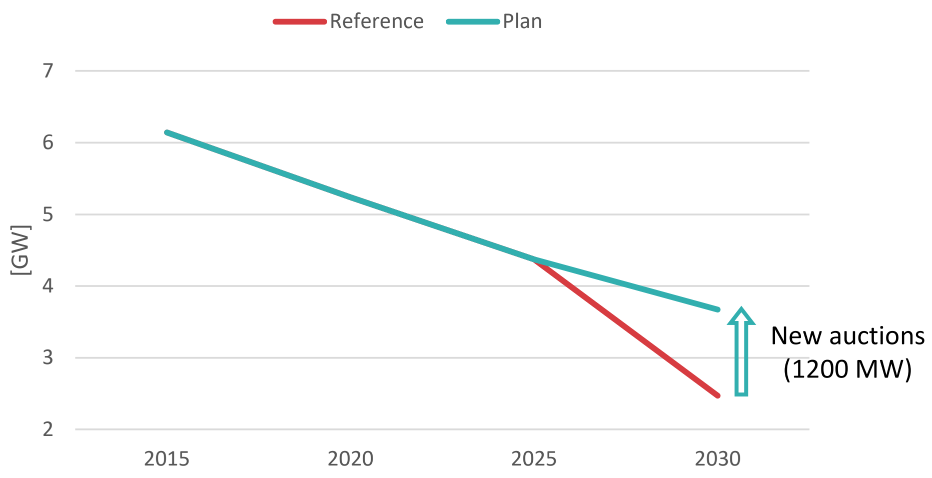

Figure 38. Expected evolution of the Spanish CHP capacity and impact of the auctions; data from MITECO (2020)

The main elements of these auctions have been presented by the Ministry in a consultation document (MITECO, 2021a). The first auction will cover 351 MW in 2022, while 442 MW and 407 MW will be auctioned in 2023 and 2024 respectively. Selected bidders can operate both on natural gas or biomass, but they will be required to design their combustion facility to be ready to operate with hydrogen and to cover 10% of their fuel demand with this energy vector. Furthermore, selected bidders will have to self-consume 30% of the electricity production. CHP units that participate in these auctions cannot exceed a 50-MW installed capacity. The support scheme embedded in the auctions is the one defined by Royal Decree 413/2014; the basic element is that it guarantees a return on investment equal to 7.09%.

3.2.3 Participation in the electricity market

The majority of the Spanish CHP fleet is operated and remunerated according to the specific supply regime described in the previous section. All the production of the CHP unit is considered to be injected into the grid and is remunerated at the price of the wholesale market plus a feed-in premium that is set according to the formulas defined by Royal Decree 413/2014, while all the electricity demand is considered to be withdrawn from the grid at the corresponding tariff. Therefore, these plants do not actively participate in the electricity market, presenting bids or accepting commercial and operational commitments, since they just inject all of their electricity production to the network[18]. However, they are exposed to the market price, since the feed-in premium is a fixed amount. This remuneration scheme has a duration of 25 years, unless a major refurbishment takes place, which could justify an extension of the supply regime.

There is a large uncertainty regarding how CHP plants will be operated and will participate in the market once their specific supply regime ends. The rest of this subsection describes the main segments

[18] Of course, CHP units must inform the network operator, commonly the distribution system operator, of any planned maintenance, connection or reconnection to the grid.

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of the Spanish electricity market, including some that could become a reality just in the next years, as the Spanish capacity market.

3.2.3.1 Day-ahead and intraday markets

The day-ahead market session takes place every day of the year at 12:00 CET to define commitments and prices for the twenty-four hours of the next day (OMIE, 2022a). The price and volume of energy at a specific hour are established through the intersection of the supply and demand curves. The buying and selling agents that are located in Spain or Portugal will present their bids to the day-ahead market through OMIE, which is the only NEMO in those countries. Their buying and selling bids are accepted based on their economic merit and depending on the available capacity for interconnection between price zones, through the European algorithm EUPHEMIA.

The algorithm determines the market clearing prices for each scheduling period. The objective of the algorithm is to maximize social welfare while accounting for the interconnector capacities across Europe. The algorithm performs a merit-order listing to obtain the market price (equal to the equilibrium price). In an interconnected European system, the matching process in the market takes place in two phases. First, energy offers are matched without considering the interconnector capacities. When the resulting schedule is infeasible due to interconnector constraints, the market splits into two zones accounting for the constraints, giving rise to two different prices. This process is called market splitting. Market splitting is rare in the Spanish-Portuguese border (2.3% of the time in 2021) while moderately common in the Spanish-French border (65.2% in 2021). The maximum day-ahead price limit is 3000 €/MWh and the minimum is -500 €/MWh.

The results from the day-ahead market, based on free contracting between buying and selling agents, represent the most efficient solution from an economic point of view, but it is also necessary for it to be viable from a physical point of view. As such, once these results are obtained, they are sent to the system operator (*Red Eléctrica de España*, or REE, in Spanish), who validates their technical viability. This process manages the technical restrictions in the system and ensures that the market results can be technically accommodated on the transmission network. As such, results from the day-ahead market may be altered, giving rise to a so-called viable daily program.

The commercial positions defined in the day-ahead market can be modified in the intraday market. The latter is an essential tool that allows market agents to adjust the day-ahead market schedule by submitting selling and purchasing bids for energy, according to their expected needs in real time.

In Spain, the intraday market is currently structured around six discrete auctions and a continuous cross-border European market (OMIE, 2022b). The time schedule of the intraday auctions is presented in Table ix. This time plan has been recently reformed to comply and coordinate with European auctions. As with the day-ahead market, intraday auctions follow the marginal pricing model and the market coupling model for the borders that it manages. The maximum offer price is set at 9 999 €/MWh and the minimum offer price is -9 999 €/MWh

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Table ix. Time schedule of Spanish intraday electricity auctions (OMIE, 2022b)

	SESSION 1°	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Auction Opening time	14:00	17:00	21:00	1:00	4:00	9:00
Auction Closing time	15:00	17:50	21:50	1:50	4:50	9:50
Matching Process	15:00	17:50	21:50	1:50	4:50	9:50
Results publication (PIBCA)	15:07	17:57	21:57	1:57	4:57	9:57
TSOs Publication (PHF)	16:20	18:20	22:20	2:20	5:20	10:20
Schedule Horizon (Timing periods included in the horizon)	24 hours (1-24 D+1)	28 hours (21-24 y 1-24 D+1)	24 hours (1-24 D+1)	20 hours (5-24)	17 hours (8-24)	12 hours (13-24)

Beyond these discrete auctions, Iberian market agents can also modify their day-ahead commitments through the European continuous trading (also referred to as Single Intraday Coupling, or SIDC). The purchase and sale bids of energy introduced by market participants in a country may be matched by the orders submitted in a similar manner by the market participants in any other country that is connected to the central computer system, provided that there is capacity to cross-border transport available between the zones.

Continuous trading is coordinated with discrete auctions as showed in Figure 39. After the clearing of each intraday auction, the continuous market platform is open for the trade of energy for the remaining hours of the market day. The continuous trading stays open until the next auction, when it must be closed to allow the auction clearing.

Figure 39. Interaction between discrete intraday auctions and continuous trading in Spain (OMIE, 2018)

Also the results of intraday auctions are sent to the system operator for validation according to technical constraints.

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3.2.3.2 Balancing and ancillary services

The Transmission System Operator (TSO) Red Eléctrica de España (REE) is responsible for facilitating the balancing market. The balancing market products in Spain are called primary regulation (FCR, in European regulations), secondary regulation (aFRR), tertiary regulation (mFRR) and replacement reserves (RR). Except for primary regulation, all balancing products are procured in a competitive market-based mechanism. The TSO publishes the reserve requirements for the following day after the clearing of the day-ahead market. Market players can submit their offer bands (e.g., capacity availability for aFRR service) for the corresponding ancillary service within the gate closure period. If during the real-time operation, there is a need for activation, the TSO activates the product. The schedule of the balancing market in Spain is presented in Figure 40.

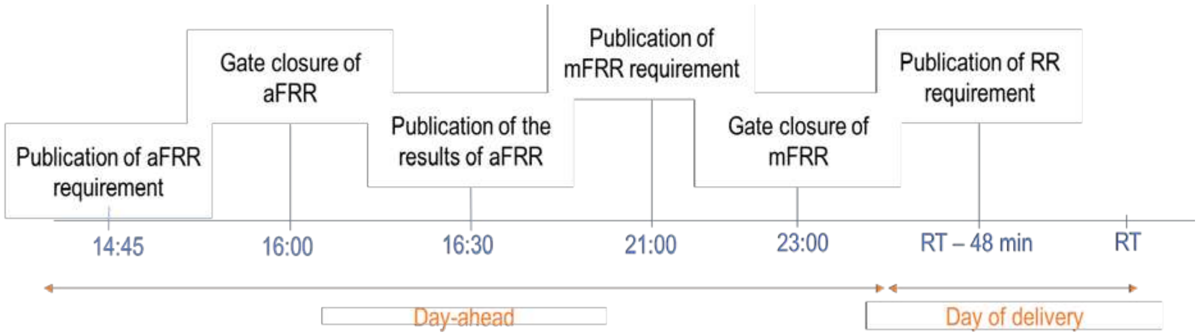

Figure 40. Schedule of the Spanish balancing markets

In Spain, FCR does not have a market-based procurement. FCR provision is a mandatory, unpaid service. Before the end of each year, the system operator has to communicate to the market players the required primary regulation reserves for the following year. The technical requirements for FCR are set by the system operator guideline (SOGL). In continental Europe, the FCR is activated when the frequency deviates by ± 200 mHz. The FCR should be fully activated within 30 seconds.

The balancing products are used to ensure the operational stability and security of the system. Hence, only qualified units can bid into the balancing market. The units that want to participate in the balancing markets undergo a prequalification process conducted by the system operator. Depending on the balancing product traded, the required product specifications differ. The necessary parameters that need to be defined for the balancing products are given in Figure 41.

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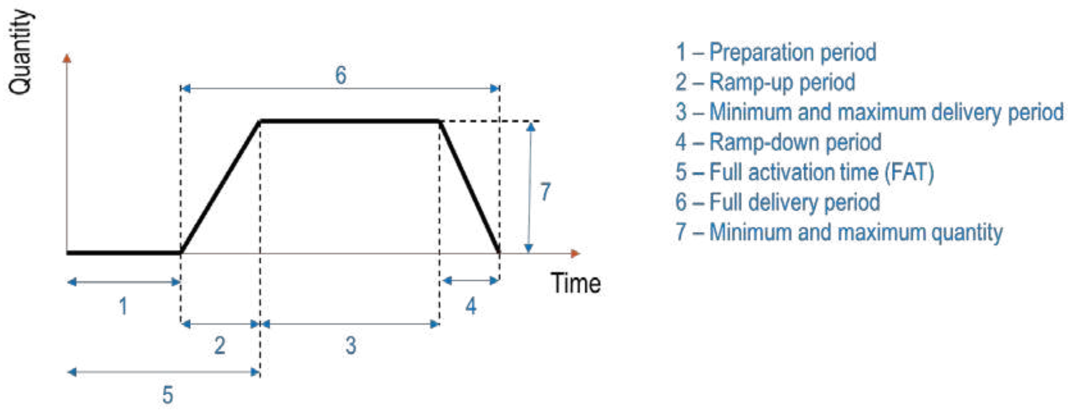

Figure 41. Standard characteristics of balancing products

The EBGL has set forth guidelines for harmonizing the balancing products across Europe. However, these proposals also need to be reflected in the national regulations. The product specifications required to participate in the Spanish balancing markets are given in Table x. To become a BSP (Balancing Service Provider), generation or consumption units must have a minimum capacity of 1 MW. Along with this, the unit should pass specific tests for offering the corresponding balancing product. BSPs should also allow telemetry in real-time so that the TSO can monitor the operational levels.

Table x. Required product specifications for balancing products in Spanish market

Technical prequalification criteria	**aFRR**	**mFRR**	**RR**
Preparation time	30 s	10 min <= x <= 15 min	x <= 30 min
Full activation time (FAT)	5 min	15 min	30 min
Bid-related requirements			
Procurement of capacity	Yes	No	Yes
Minimum bid size capacity	1 MW	N/A	1 MW
Minimum bid size energy	N/A	10 MW	1 MW
Bid symmetry	Asymmetrical	N/A	N/A
Price resolution (€/MWh)			0.01 €/MWh
Price cap			No limit
Time-related characteristics			
Frequency of bidding - capacity	Daily	N/A	Daily
Frequency of bidding - energy	N/A	15 min	
Minimum duration	15 min	2 hrs	15 min
Maximum duration			60 min
Product resolution	1 hour (or blocks)	15 min[19]	15 min
Validity period		15, 30, 45 or 60 min	15, 30, 45 or 60 min
Settlement - capacity	Marginal Pricing	N/A	N/A
Settlement - energy	Hybrid	Marginal Pricing	Marginal Pricing

The Spanish electricity market also relies on a segment to solve technical constraints (the day-ahead and intraday markets are cleared with a uniform price, without considering the grid, and the solution

[19] Spain recently added 15 min products in the mFRR markets through the resolution of 17th March 2022 (*Resolución de 17 de marzo de 2022*)(Comisión Nacional de los Mercados y la Competencia, 2022)

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may be unfeasible). The constraint violations identified during the commercial trades are solved in the technical constraints' market (*mercado de restricciones técnicas*, in Spanish). It should be noted that the Spanish technical constraints market not only manages the power grid congestions, but also other technical limitations such as insufficient balance reserves and insufficient voltage regulation reserves.

Technical constraint market open at 12:00 on the day before delivery and remain open until 15 minutes after the publication of the basic daily operating program (PDBF). After publishing the PDBF results, the system operator runs a security analysis on the PDBF results considering demand forecast, RES forecast and expected availabilities of network elements and scheduling units. The technical constraints market takes place in two phases. In the first phase, the TSO makes program modifications to solve the constraints and take precautions to avoid the emergence of new constraints. Additionally, the distribution level congestion will be considered in the program if the DSO cannot solve the resulting congestion through topological changes or other remedial actions. In phase two, the TSO makes additional adjustments to balance generation and demand. For real-time congestion management markets, the market players can continuously update the secondary regulation bids to provide technical constraint relief.

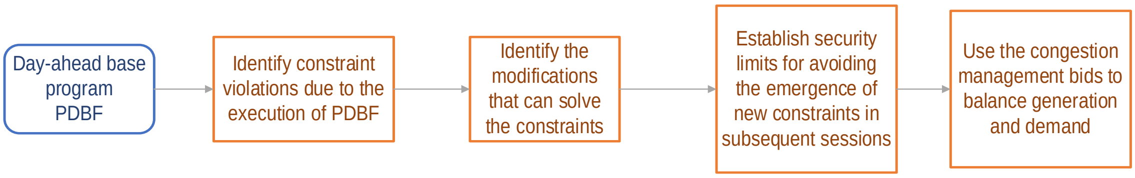

Figure 42. Phases of congestion management market in Spain

Until recently, only generation units (renewable, non-renewable or pumped hydro) could participate in the technical constraint market. In January 2022, the operational procedure for the technical constraints market was updated allowing the participation of aggregators, demand response and energy storage. The bids for the technical constraints' market should be simple. Units obliged to submit the selling offers or buying offers have to submit the offers for the whole available capacity after the PDBF programming.

Table xi. Bid structure in technical restrictions market

Type of bid	**Generation, consumption, pumped consumption**
Upward energy - price	In 1-10 divisible blocks of increasing price – quantity pairs
Downward energy - price	In 1-10 divisible blocks of decreasing price – quantity pairs
Only for thermal units - Pre-warning periods for cold and hot start-ups	Time (minutes)
Only for thermal units	- Cost for keeping the unit coupled for one hour - Cost per programmed unit - Cold start-up cost

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- Optional complex bidding[20]	- Hot start-up cost

Like the preceding markets, the aim of the market operator is to procure the resources cost-efficiently ensuring operational security. For increasing the energy from the PDBF program to solve restrictions, the selection of bids is such that the difference between the cost of re-dispatch volume from the PDBF program and the cost of the same volume of electricity in the day-ahead market price is minimum. When two offers have the same cost and have the same effect on the security of the system, priority is given to renewable sources and high-efficiency cogeneration units. For decreasing the energy from PDBF program, the contribution of the dispatch schedule of each unit to the identified restriction is considered. This is a major factor in determining which unit has to reduce the generation.

Compared to the DA and ID markets, the settlement of the congestion management market is less straightforward. This is because the corrections can be applied both to the units that bid in the CM market and also to the units that did not participate in the market. Hence, the settlement differs based on the status of the market player and on which phase of the market the unit was allocated. In the first phase, the generation that has to increase its production will be paid at its bid price whereas the generation which had to dispatch down will be settled at the day-ahead market clearing price (essentially, cancelling a volume equal to the re-dispatch volume from the day-ahead position). In the second phase, the upward re-dispatch energy is settled at a pay-as-clear price from the merit-order list of upward bid offers and the downward re-dispatch energy will be settled at a pay-as-clear price from the merit-order list of downward bid offers. When units that did not actively bid into the market are re-dispatched, the remuneration is defined as the product of a predefined coefficient and the day-ahead market price.

The Spanish regulation 24/2013 and Royal decree of 413/2014 opened the ancillary services market to qualified CHP units and established priority rules for CHP plants with high efficiencies during the market clearing process[21]. Despite the regulatory support, the participation of the CHP plants in ancillary service markets remains low, except for congestion management markets (shown in Table 1). For context, the total installed capacity of cogeneration plants in 2021 was 5,690 MW, i.e. 5% of the total installed capacity in Spain. The share of CHP in DA market allocation during this period was 11.24%.

[20] Complex bids are considered only when the unit have to be started up from zero. The power production of the unit must be zero in one or more hours (or scheduling units) in the scheduling horizon. For multi-shaft combined generation, the hot start can also be considered when an additional gas turbine is required to start-up.

[21] When two power plants have the same cost, the priority is given to the renewables, biomass and high efficiency CHP plants.

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Table xii. Market share of CHP in different ancillary service markets in Spain in 2021

Market	Market share (%)	
	Upward	Downward
Congestion management	0.008	9.372
aFRR	0.483	0.498
mFRR	0.374	0.283
RR	1.443	0.369
Real-time congestion management	0.004	2.360

The main competitors for CHPs in the ancillary service markets are combined cycle, hydro plants and pumped hydro plants. Even though the pumped hydro makes up only 2.9% of the generation mix in Spain, lower than the CHPs, its market share is substantially higher in ancillary markets compared to CHPs. In contrast, the share of pumped hydro in the DA market is only 0.72%. It can be safely assumed that generation technologies like pumped hydro have created their business use case around the ancillary service markets whereas CHP plants still depend on wholesale electricity markets. Increasing the flexibility of the existing CHP plants can increase the participation of the CHPs in the ancillary service markets.

Along with the technical challenges, there might be country-specific barriers that affect the participation of CHP plants. A report on CHP plants in Spain claims that the lack of awareness about CHP plants among the policymakers is a contributing factor for the reduced interest in CHP technologies (Cogeneration Observatory and Dissemination Europe, 2014). The economic crisis in 2012 is also assumed to have played a crucial role in reducing the CHP installation numbers. Spain also has an issue of overcapacity in the generation side. Considering all these factors, it is questionable whether it is possible to full utilize the full flexibility potential of the remaining CHP plants without explicit regulatory supports in short-term.

3.2.3.3 Capacity market

Spain currently has no capacity market in place (it used to have capacity payments, whose duration has expired and now cover a negligible share of electricity generation). In 2021, the Government published a proposal that outlines the design of a Spanish capacity market (MITECO, 2021b). No progress has been registered since then and the capacity mechanism would have to comply with the new and demanding rules set by the Clean Energy Package. However, it is interesting to envisage which kind of participation from cogeneration units may be expected in this market segment.

The proposal considers a capacity market with a design that mimics the British capacity market. Eligible resources would be assigned de-rating factors and would be allowed to offer their de-rated capacity in the market. The capacity market would be based on a centralised auction with a sealed-bid and pay-as-bid design. Capacity providers are remunerated for their availability and are required to offer their de-rated capacity in the energy market at times of scarcity.

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Auctions would be launched five years ahead of delivery. Existing resources would be entitled to 1-year contracts, while new entrants would sign 5-year contracts, a duration that is supposed to allow them to better hedge their risk. Existing resources are required to comply with the CO_2 emission limits defined by the Clean Energy Package, while new entrants must have emissions equal to zero, a very ambitious target that is not commonly found in other European capacity mechanisms.

It is hard to envision a large participation of CHP units in this mechanism. First of all, the current support scheme for cogeneration in force in Spain provides a feed-in premium that is expected to guarantee a reasonable return to investments. According to an assessment published by the Spanish regulator (CNMC, 2021b), cogeneration units enrolled in the support scheme would not be allowed to receive the capacity remuneration. This is true for existing CHP units, but it would probably be true also for new units that may enter the system through the specific auctions for cogeneration that may be held until 2024.

Those existing CHP units whose enrolment in the support scheme gets to an end after 25 years may participate in the capacity market. However, they may not comply with the stringent emission requirements set by the Clean Energy Package. In fact, CNMC (2021b) takes into account ACER Decision 22/2019, according to which the methodology to compute emissions should disregard the heat production when assessing the efficiency and the emission of the cogeneration plant. Therefore, only new CHP projects that are completely carbon-neutral (e.g., driven by sustainable biomass, renewable hydrogen, or with carbon capture and storage) and do not receive any further subsidy would be allowed to participate in the Spanish capacity market.

3.2.4 Participation in the heating market

In Spain, there are 494 networks for district heating and cooling (75% heating and 25% cooling), totalling 1 639 MW of installed thermal capacity and 810 km of pipelines (Adhac, 2021). The installed capacity has been steadily growing, although the growth slowed down during the pandemic, as it can be observed in Figure 43.

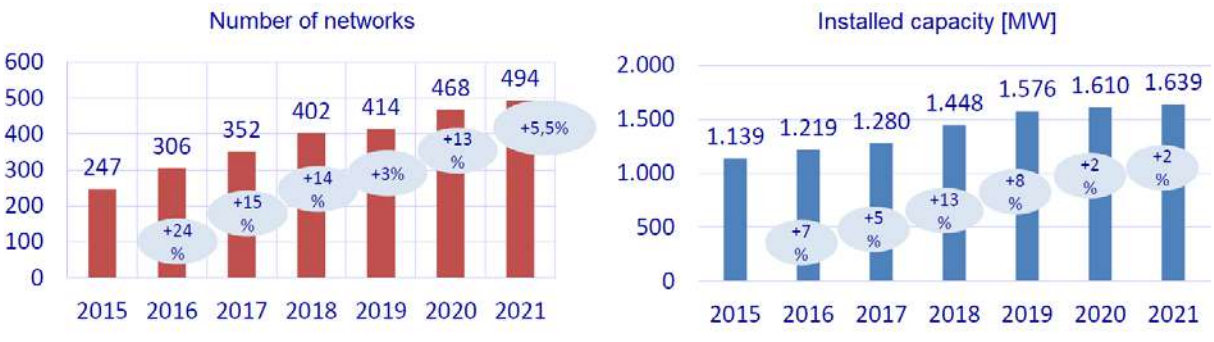

Figure 43. Evolution of heating networks in Spain (Adhac, 2021)

The geographical distribution of the Spanish heating networks presented in Figure 44 shows how the climate and the heat demand are the main driver of these installations, with colder regions accounting for the largest thermal capacity.

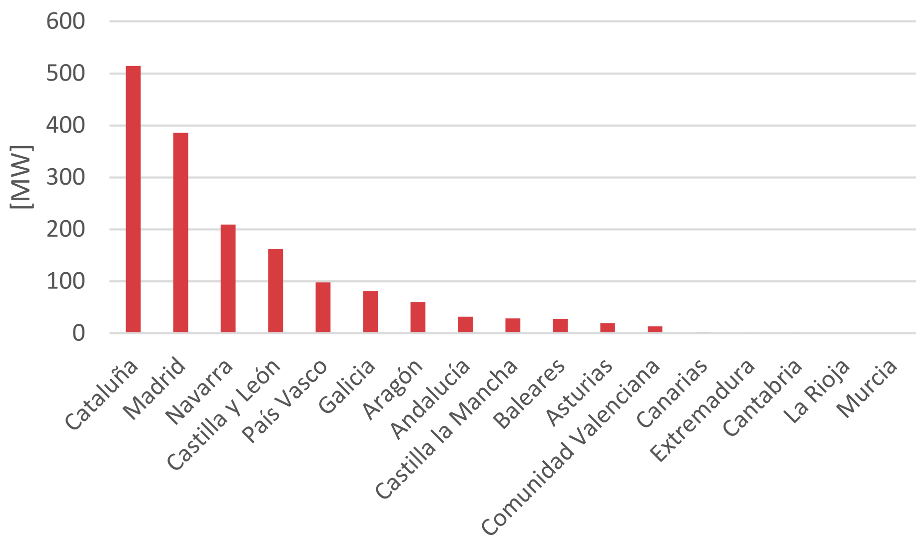

Figure 44. Distribution of Spanish heating networks in the national territory; data from Adhac (2021)

Only 22% of Spanish heating networks serve industrial premises, being commercial (46%) and residential (32%) the two sectors with the highest participation. Very different business models can be found in the country, with public, private, or mixed ownership covering one third of the market each. The most widespread fuel for district heating is natural gas, which covers almost 60% of demand, the rest being covered by biomass (Figure 45). There is no data on the percentage of district heating that is currently being served by combined heat and power, but it does not seem to be a widespread technological alternative.

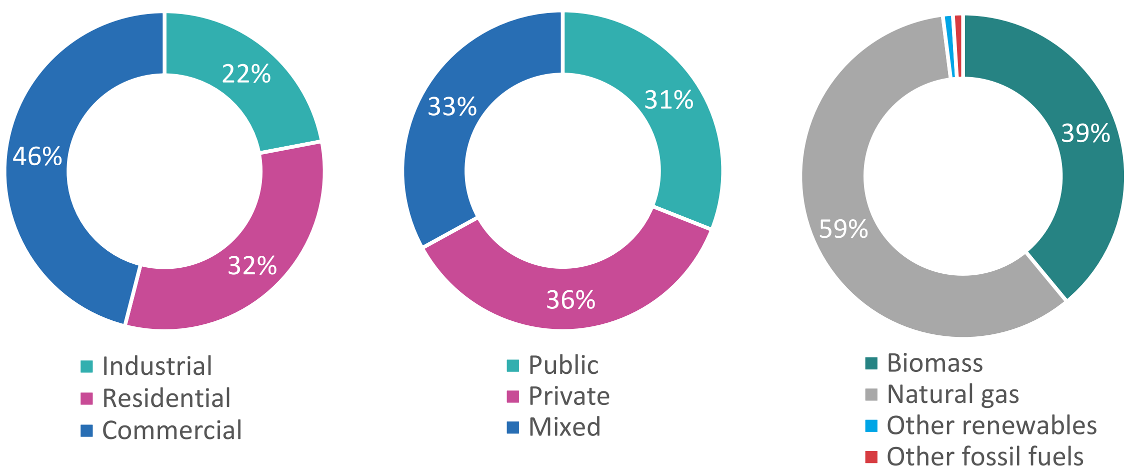

Figure 45. Data on Spanish heating networks, by sector, by ownership, and by fuel; data from Adhac (2021)

Biomass-driven heating networks are showing a more rapid growth than the rest of technologies, as it can be observed in Figure 46. This could represent a significant trend for the future, with biomass surpassing natural gas as the main fuel for district heating in Spain.

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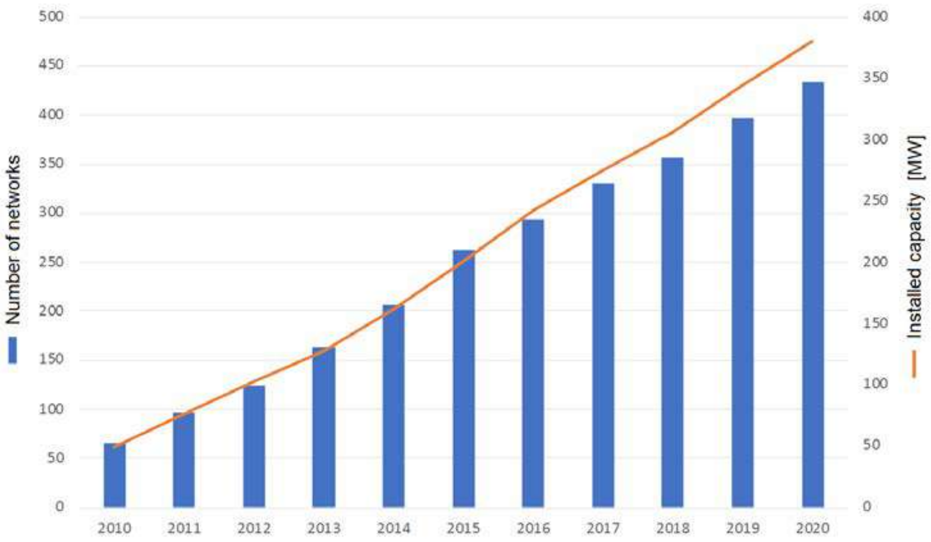

Figure 46. Evolution of biomass-driven heating networks in Spain (AveBiom, 2021)

The geographical distribution of biomass-driven heating networks mimics the one already shown for all district heating, but it is affected by another factor, i.e., the availability of biomass, as it can be observed in Figure 47.

Figure 47. Geographical distribution of biomass-driven heating networks in Spain (AveBiom, 2021)

Although heating networks are covered under the Regulations for Thermal Installations in Buildings (*Reglamento de Instalaciones Térmicas en los Edificios*, or RITE, in Spanish), which was recently reformed through Royal Decree 178/2021, there is not a comprehensive regulatory framework for district heating in Spain, at list at the country level. As already mentioned, there is a lot of different business models that coexist in Spain, ranging from industrial heating networks that are owned by the same consumer of the heat to municipalities who own and operate, either directly or through a concessionaire, a heating network serving a certain neighbourhood within their territory.

In the case of district heating for the residential and commercial sector, there is always an active role from the municipalities, which can either initiate the project, for instance by defining a territorial concession and launching a tender for project developers, or are required to provide administrative

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permissions. At this stage, some sort of regulation may be imposed on the project developer (Adhac, 2012).

Tariffs for end-users are commonly the main element of these regulations. Very different ratemaking options are found in Spanish heating network. Tariffs commonly include a fixed part, which is expressed either as a per-kW_{th} charge or as a fixed charge per month, and a variable part, with a charge expressed in terms of energy (€/MWh) or volume (€/m^3). The regulation regarding tariffs usually include also some specific provisions for indexation. Commonly, fixed charges are indexed to the retail price index, while variable charges are updated according to the evolution of the price of the fuel in a liquid market (for instance, the price of diesel oil or the price of gas in the regulated tariff for residential customers; FEMP, 2015). Some projects also consider a connection charge, which covers part of the capital expenditures, in such a way that the user co-finances the project.

Another element of these regulations is related with the obligation to connect consumers. In some cases, the decision is left to the operator of the heating network, based on an analysis of the potential revenues. In other cases, especially when there is a concession, the operator is required to connect all the users willing to connect, usually at the building level.

There are several support schemes for installing heating networks, which are commonly managed at the regional or provincial level. Some of these schemes are operated through European funds, as the European Regional Development Fund (ERDF; AveBiom, 2021). District heating could also access the large funding from the Spanish Recovery, Transformation and Resilience Plan (GdE, 2020), which will provide finance for projects that improve energy efficiency in buildings.

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3.3 Germany

Combined heat and power generation, referred to as KWK (Kraft-Wärme-Kupplung), is an important pillar in the German energy mix. While not as dominant as in other European countries, its contribution of 20% to the German electricity mix and importance for heating networks makes the German CHP market the largest in Europe in absolute terms. The following section presents the German national context, including past developments and future perspectives. It analyses the role of CHP in electricity markets and heat markets.

3.3.1 Country context

Much of Germany's thermal electricity generation fleet is utilising off-heat. In 2019, these power plants provided 19.6% of the country's net power supply (Umweltbundesamt, 2020). Hence, the total electricity generation capacity of CHP is estimated to be between 20-25 GW.[22] This number is in stark contrast to high-efficiency CHP installations that fall under the KWK-regulation[23] and are eligible to support payments, which only account for a total generation capacity of 9 107 MW (Umweltbundesamt, 2020). As shown in Figure 48, most of these (97%) are small-scale installations between 1 kW and 10 MW. In contrast, more than 45% of all installed capacity stems from a relatively small number of large-scale installations (0,43%).

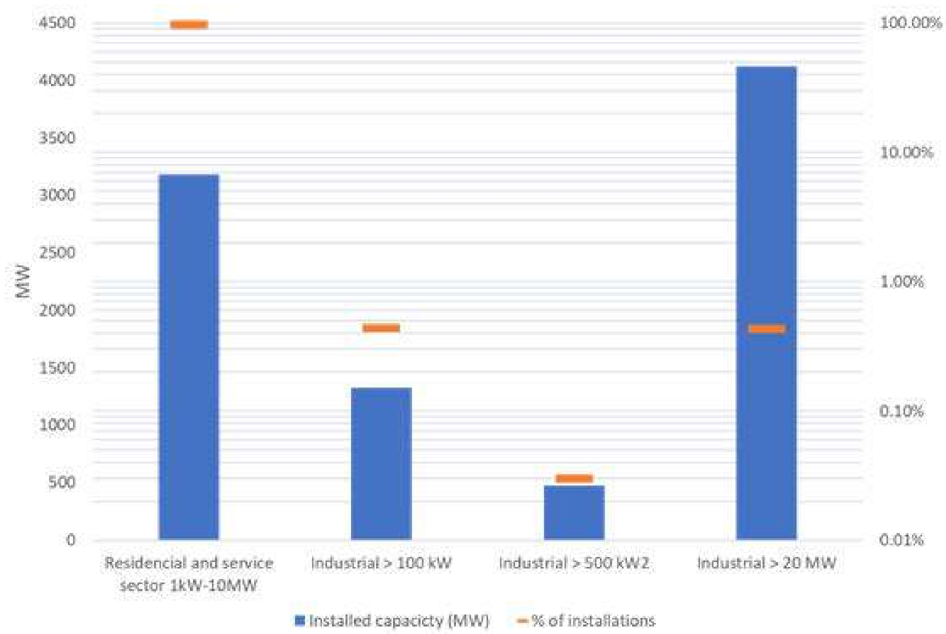

Figure 48: Installed capacity and installations by size and sector. Adopted from Umweltbundesamt (2020)

The role of large thermal power plants with CHP in the electricity mix is also reflected in the primary energy consumption of Germany's CHP plants. While the biomass share has increased significantly

[22] Extrapolation of data presented by (Gores, 2011).

[23] Gesetz für die Erhaltung, die Modernisierung und den Ausbau der Kraft-Wärme-Kopplung (Kraft-Wärme-Kopplungsgesetz – KWKG 2020)

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over the last decades, reaching 33.1 TWh in 2018, a significant share of coal and lignite as primary energy sources remained relatively constant over the last years (Figure 49).

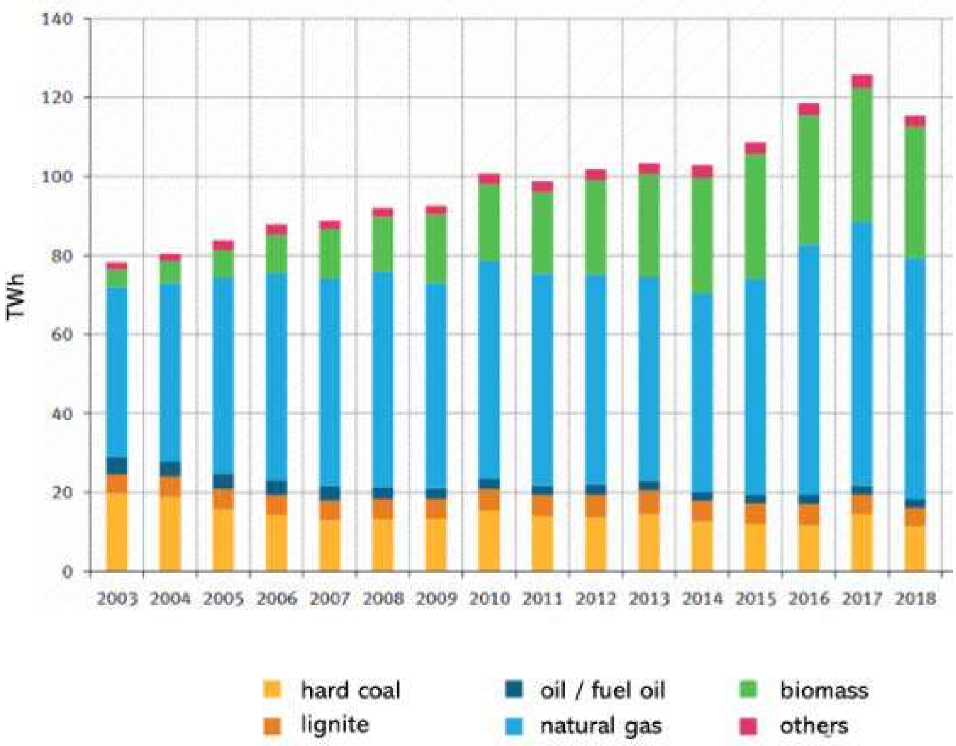

Figure 49: Electricity consumption by CHP installations in Germany. Adopted from Umweltbundesamt (2020)

3.3.2 Regulatory context

The liberalisation of the electricity system in Germany has advanced in line with European legislation. However, district heating networks remain natural monopolies that are not subject to energy market liberalisation. Hence, district heating networks are not subject to the German Energy Act (Energiewirtschaftsgesetz). Therefore, market-based instruments to foster the installation and operation of CHP installation have been oriented toward electricity generation by CHP. The first CHP law (KWK-regulation) to support investments in highly efficient CHP technology came into force in 2002 and has been revised multiple times since then. Since 2015 the law includes a target of 110 TWh of electricity generation from CHP until 2020 and 120 TWh until 2025 (KWKG 2020).

The law includes various provisions to support CHP installations of all sizes. For example, small-scale installations of up to 2 kW receive a feed-in tariff of 0.04 €/kWh for up to 60 000 hours of operation. Up to 100 kW operators can request that the system operator pays production at the average market price from the last quarter. Installations with more than 100 kW are required to use generated power for self-consumption or sell it via direct marketing. New installations above 1 MW are subject to national tendering procedures to award feed-in-premiums for electricity generation. These tenders are designed to ensure sufficient investment to meet the targets set in the CHP law with two separate tendering procedures for conventional and innovative CHP installations. As defined by the Federal Office for Economic Affairs and Export Control, innovative systems have an annualised energy yield of at least 1.25 per unit of consumed fossil energy source or biomass. Biomass use is only considered

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innovative if used for heat pumps. Tenders for conventional and innovative CHP installations are held twice per year, with tendered volumes varying between 100 and 50 MW per auction for conventional CHPs and 25 to 30 MW for innovative systems. However, in about half of the tenders organised since 2017, the total capacity of the awarded projects has remained lower than the tendered volume (KWKG 2020 § 7c Kohleersatzbonus). The highest accepted bids have remained relatively constant at around 0.05 €/kWh for conventional CHP and 0.11 €/kWh for innovative systems. An additional subsidy support mechanism exists for investments in systems that replace coal and lignite as the primary energy source for cogeneration units. The so-called "Kohleersatzbonus" (coal replacement bonus) is a one-time payment per kW of installed capacity that varies depending on the age of the installation and year of retirement).

Table xiii. Payments to power plant operators replacing coal and lignite-based CHPs

"Kohleersatzbonus" in €/kW		In-service date for new or retrofitted CHP installation							
		2022	2023	2024	2025	2026	2027	2028	2029
Year installed	1975-1984	20	20	15	10	5	-	-	-
	1985-1994	225	225	210	195	180	165	150	135
	Since 1995	390	390	365	340	315	290	265	240

Since energetic use of biomass is considered renewable, CHP installations using biomass, biofuels, and biogas are also subject to the German Renewable Energy Sources Act.[24] Since 2017, this act has included a provision referred to as "Maisdeckel" (corn cap), defining that biomass units are only allowed to consume up to 50% corn or wheat, which applies to CHP. To avoid cross-subsidisation, biomass CHP unit operators must opt to receive support payments under the KWK-regulation or the EEG. The EEG only supports units with a total capacity below 500 kW. Units with up to 100 kW can receive feed-in remuneration, while the system operator has a physical offtake obligation for generated electricity. For units above 100 kW, direct marketing is obligatory. Units have to sell their generation on the electricity market and receive a market premium calculated based on the average monthly market price ex-post. The market premium is determined via public tendering procedures.

3.3.3 Participation in the electricity market

Both KWK and EEG expose CHPs to electricity market prices and allow them to provide balancing services. However, the actual market incentives for CHP operators are relatively small. CHP does not take part in the strategic reserve mechanisms that are used in Germany as capacity remuneration mechanisms.

[24] Gesetz für den Ausbau erneuerbarer Energien (Erneuerbare-Energien-Gesetz - EEG 2021)

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3.3.3.1 Day-ahead and intraday markets

The German day-ahead and intraday electricity markets are part of the European Power Exchange (EPEX). While the markets are organised on a national level (incl. Luxemburg and Austria), all markets organised by the EPEX in central-western European countries are coupled via Multi-Regional Coupling (MRC) with other European power markets in Southern, Northern and Eastern Europe, covering more than 85% of Europe's electricity consumption since 2015 (EPEX SPOT, 2022). Single intraday coupling (SIDC) between the different European markets was realised in 2018 (ENTSO-E, 2022).

The German day-ahead market follows the principles of the European liberalised electricity market design and resembles the Swedish and Spanish designs presented in sections 3.1 and 3.2. Gate closure for submitting bids to the market operator is at 12:00 h (CET) the day before delivery, while order books are open 45 days before delivery. Buyers and sellers can offer bids of one-hour length at a volume increment of 0.1 €/MWh at prices ranging between -500 €/MWh and 3000 €/MWh. Results are published from 12:50 h onwards. Complementary to the day-ahead market, intraday trading allows for adjustments to purchases and sales based on the results from the day-ahead auction. In Germany, only 15 min blocks are traded with a lead time of 30 minutes before delivery and 60 minutes for cross-border flows. As shown in Figure 50, the importance of intraday trading has increased significantly. In contrast, day-ahead volumes in the German market have declined at the same time, from more than 250 TWh in 2015 to less than 200 TWh in 2018 (EPEX SPOT, 2019).

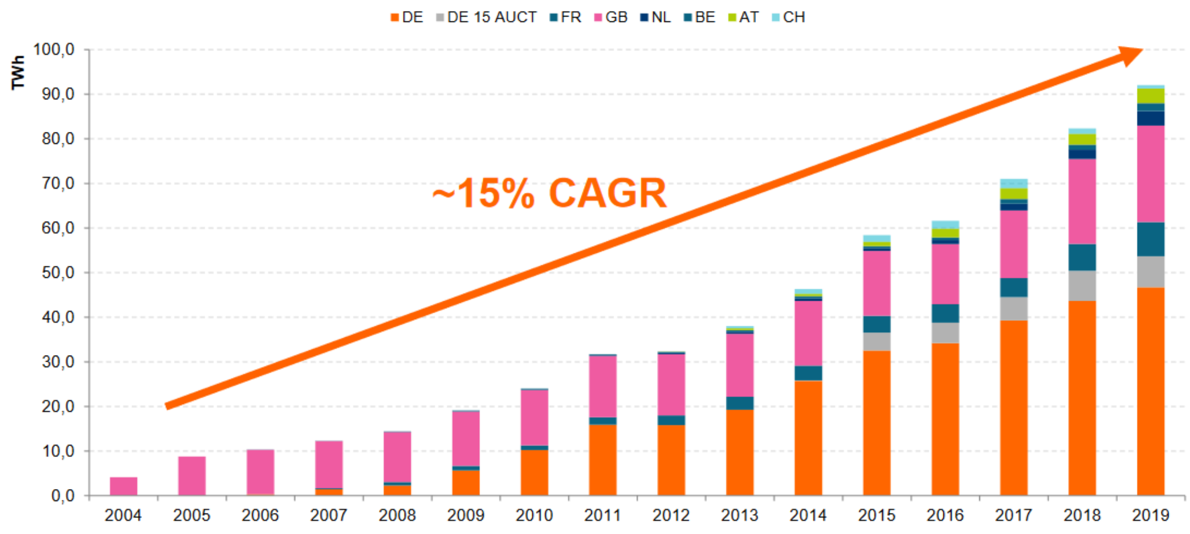

Figure 50: Annual intraday market volume (TWh), indicating the compound annual growth rate (CAGR) (Töpfer, 2020).

Depending on the size of the CHP unit, both KWK and EEG expose biomass CHP to electricity market prices. Market premium models in place calculate average-out day-ahead electricity prices over a longer period of one month (EEG) or three months (KWK), while units with an installed capacity of more than 1 MW (KWK) receive a contractually agreed feed-in premium. Since actual day-ahead market price variations have little impact on support payments and, at the same time, support payments represent a main source of income, biomass CHP operators only have a small exposure to day-ahead market prices and are show little price sensitivity and even less price sensitivity concerning intraday market prices (Jahnke, Philipp et al., 2020).

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3.3.3.2 Balancing and ancillary services

In Germany, balancing services are contracted directly by the TSOs via public tendering procedures. In order to offer balancing services, plant operators have to undergo a prequalification process established by the four different transmission system operators. Three different types of balancing services exist, each with different prequalification requirements: Frequency control (FCR), automatic frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR).[25] Various aggregators offer their services to CHP plant operators to operate in these markets as virtual power plants.[26]

CHP installations can participate in balancing markets. However, their participation in these markets is neither promoted via the KWK regulation nor EEG.

3.3.4 Participation in the heat markets

Local heat networks play an important role in various urban population centres in Germany. As shown in Figure 51, heat networks are geographically constrained to cities in the Ruhrgebiet, main population centres such as Berlin-Brandenburg, Munich, Hamburg, Frankfurt-Rhein-Main and other larger cities such as Hanover, Freiburg, Bremen or Leipzig or Stuttgart. The total network size is beyond 100 000 km, with most heat demand (86%) being met by individual networks with more than 100 km of pipe length (Engelmann et al., 2020). No validated information about the total number of heating networks exists. The German Environment Agency assumes that more than 5000 district heating networks are in service, given that 2 450 new district heating networks received funding under the KWK regulation between 2009 and 2016 (Engelmann et al., 2020). In total, about 9% or 124 TWh of all stationary thermal energy consumption was provided by heating networks in 2019, with the residential sector being the biggest consumer (41%), followed by industrial applications (38%) and the service sector (21%) (BDEW, 2020). As shown in Figure 52 the total head demand met with district heating networks has remained relatively stable over the last 20 years. While consumption in the industrial sector has increased and residential consumption has remained relatively stable, the demand in the service sector has steadily declined.

[25] For prequalification requirements, see: (50hertz et al., 2020)

[26] For example, Next Kraftwerke: https://www.next-kraftwerke.de/virtuelles-kraftwerk/bhkw-kwk

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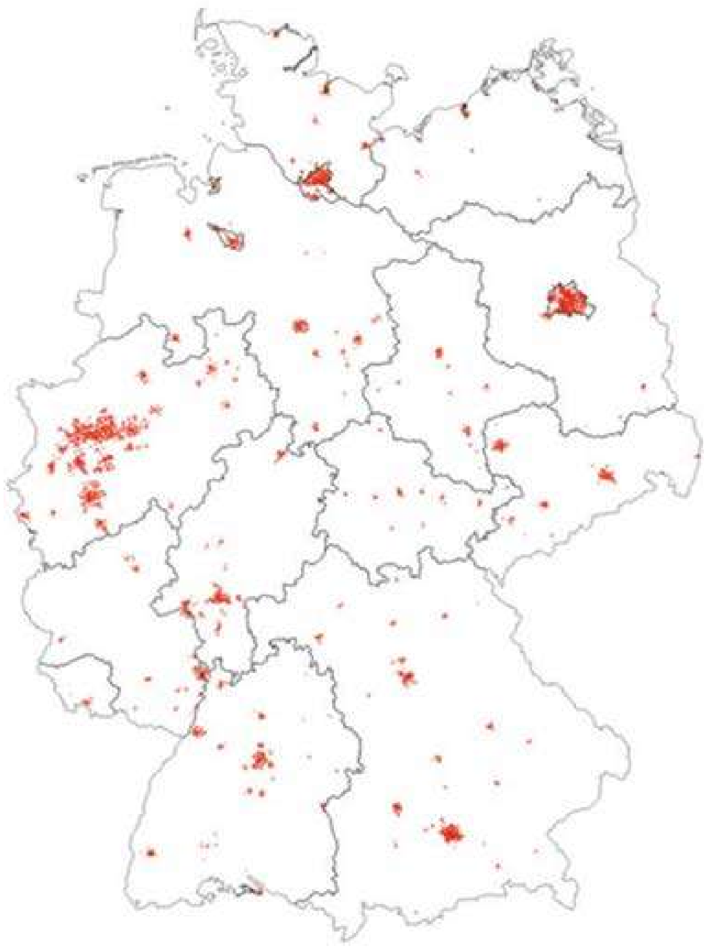

Figure 51: Spatial distribution of heat networks in Germany. Adopted from Jochum et al. (2017).

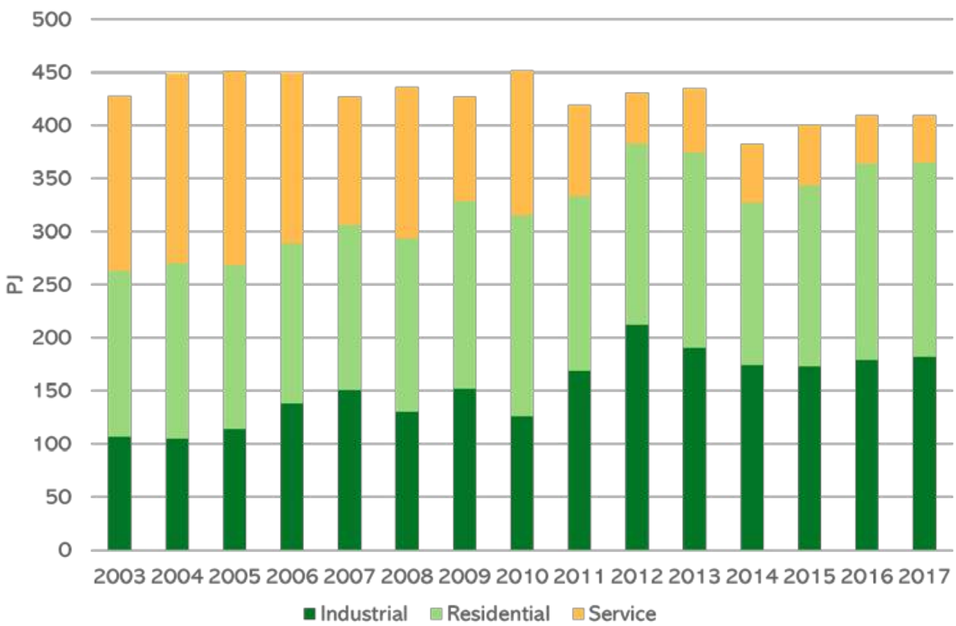

Figure 52: Historic energy demand from districting heating networks in Germany (Engelmann et al., 2020)

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As mentioned above, Germany's heat markets remain natural monopolies and are not liberalised. Participation in the district heating network is subject to bilateral contracting with the different network operators.

3.3.5 Other issues

The future role of CHP in Germany is subject to two different dimensions of the country's vision of its future energy mix. First, the Climate Change Act 2021 (Klimaschutzgesetz) foresees a reduction of CO_2 emissions by 65% compared to 1990 until 2030 and climate neutrality by 2045. Second, the aforementioned KWK regulation sets CHP production targets for 2025 and incentivises new heat network infrastructure until 2030. The perspectives for CHP can therefore be summarised as follows.

The accelerated transition toward climate neutrality has significant consequences for the expected electricity generation mix, scaling up investments in renewables while divesting fossil generation. According to Agora Energiewende (Graichen et al., 2021), meeting 2030 targets implies the quasi-phase-out of coal-powered generation capacity combined with a significant increase in natural gas from a 12.9% contribution in the electricity generation mix in 2018 to 21.8% in 2030 (Figure 53). However, after 2030 natural gas consumption is set to decline in absolute and relative terms.

As such, the current targets for electricity production from CHP set by the KWK-regulation for 2025 of 120 TWh per year seem little aligned to an acceleration of the energy transition. Note that this absolute annual generation target was already surpassed for the first time in 2017. Hence the volume and functioning of future tenders for new CHP and innovative CHP capacity are not expected to change significantly as long as the KWK regulation is not revised and streamlined to more ambitious decarbonisation targets. This also means that biobased CHP remains largely excluded from tenders for innovative CHP capacity.

Figure 53: Net electricity and import balance for climate neutrality until 2045 (Graichen et al., 2021)

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The extension and modernisation of existing heat network infrastructure will receive continuous support until at least 2030 under the KWK-regulation, encompassing feed-in payments for new CHP installations and the "Kohlebonus" to phase-out coal and lignite consumption for heat generation. A study published by the German Environment Agency (Umweltbundesamt) in 2021 foresees that the contribution of heating networks in the energy mix for buildings is expected to increase from 9% to 20% until 2050 (Engelmann et al., 2020). Hence, the importance of heat networks and CHPs for heat provision is expected to increase over the upcoming decades.

As mentioned above, current legislation has not been aligned to the revised national decarbonisation targets and, as such, does not provide a clear vision for the role of innovative CHP in the decades to come. As such, the gap in the current legislation, as shown in Figure 54, remains. The KWK regulation continues to provide funding opportunities for new CHP, but a clear alignment of funding schemes to the needs of a decarbonised energy system remains outstanding. As such, the future role of CHP and, in particular, the reframing and redefining the role of bio-based CHP remains uncertain.

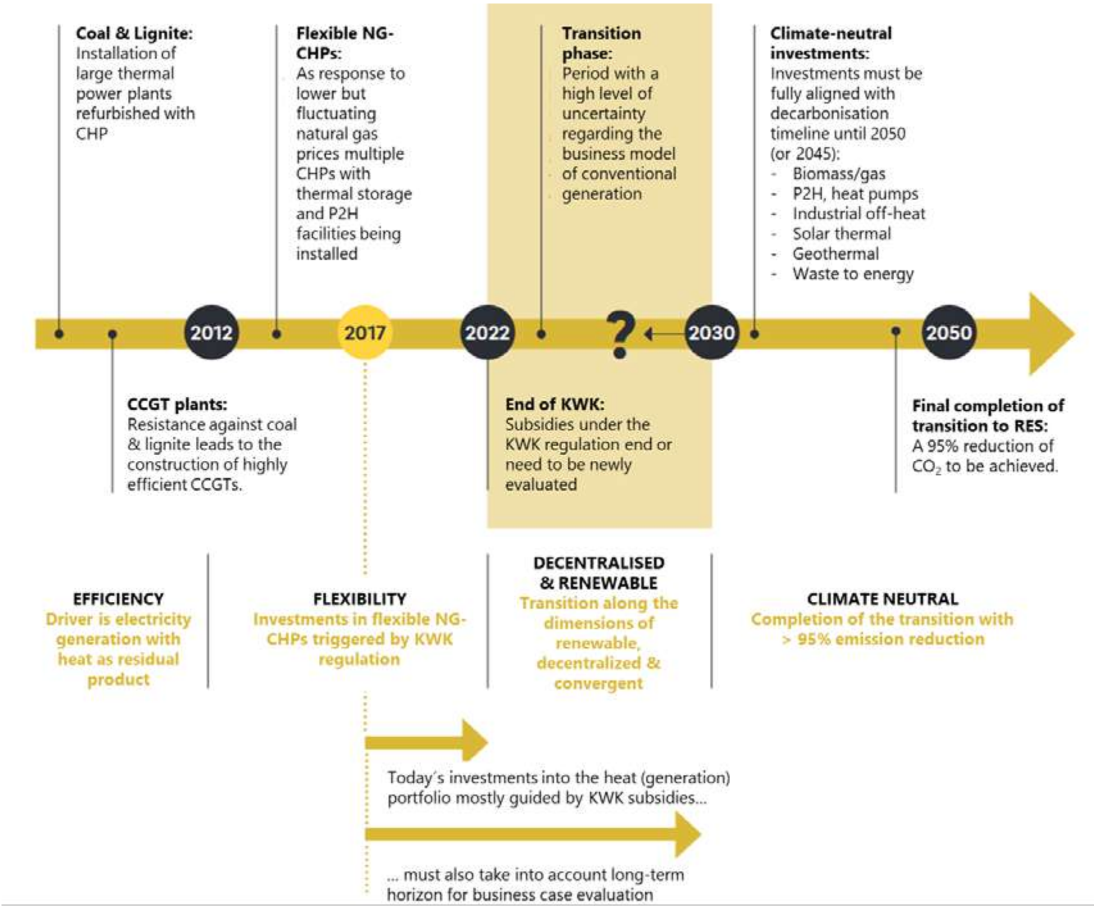

Figure 54: Historical development of combined heat and power in a German context, first presented by Henzelmann et al. (2017), translated and revised by the authors of this report.

3.4 Italy

3.4.1 Country context

Italy has the second largest CHP fleet in Europe, in absolute terms, only behind Germany. Cogeneration had historically a large role in the power sector; currently, 55% of the fleet of thermal power plants produces also heat. However, only half of this capacity can be considered as high-efficiency cogeneration according to the European regulation. When looking at the installed capacity, combined cycles are by far the most common technology, covering more than 75% of the CHP fleet. Also reciprocating engines and open-cycle gas turbines have significant shares, as shown in Figure 55.

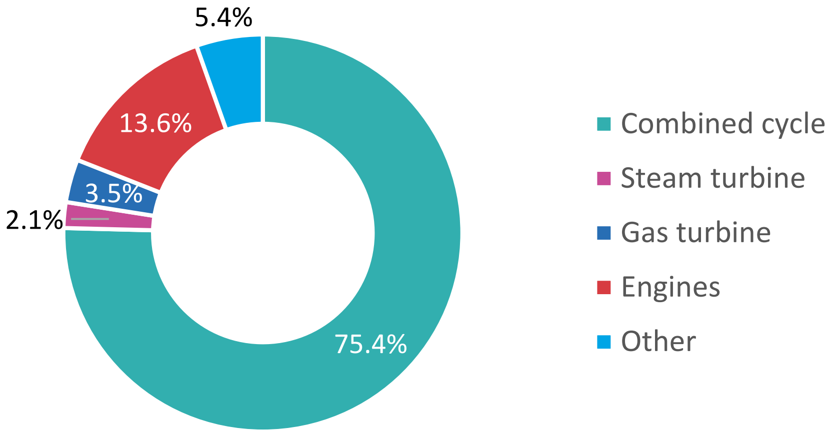

Figure 55. The Italian CHP fleet divided per technology (installed capacity); data from MSE (2020)

In terms of final uses, almost two thirds of the Italian CHP fleet serve industrial premises, while the remaining third is commonly operated within a district heating network (Figure 56). Also for heat networks, the most common technology is represented by combined cycles.

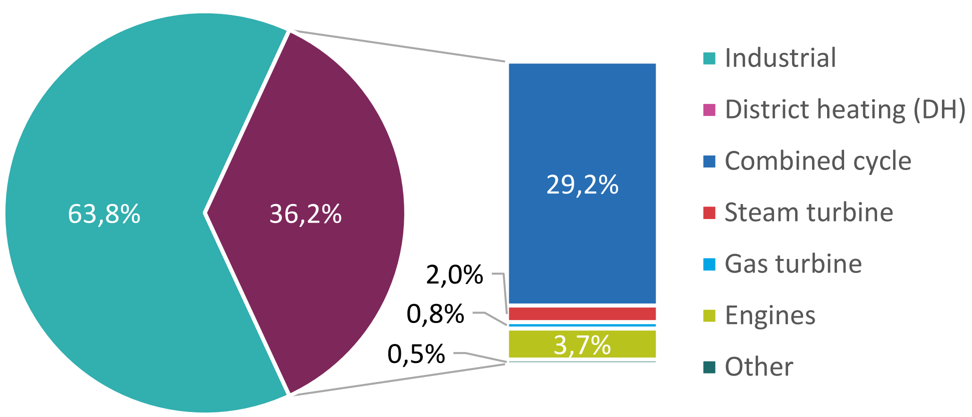

Figure 56. Final uses of Italian CHP (installed capacity); data from MSE (2020)

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These final uses evidently influence the geographical distribution of CHP plants over the Italian territory, as presented in Figure 57. The largest installed capacity is found in regions with a stronger industrial sector, also located in the South of the country or in its islands, or with higher demand for heat in winter (see also Figure 61).

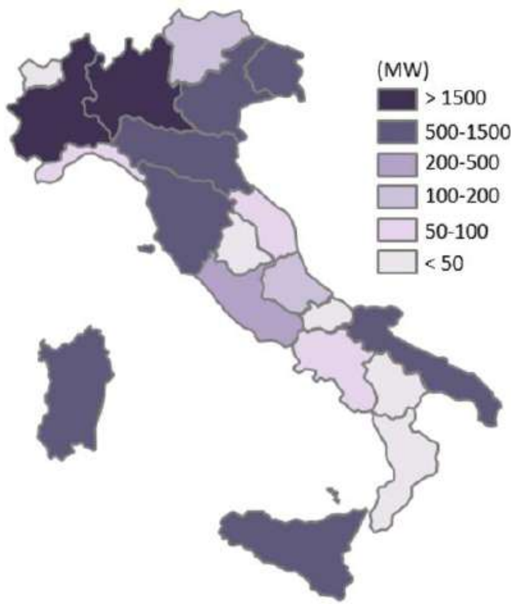

Figure 57. Geographical distribution of the Italian CHP fleet; chart from MSE (2020)

In terms of energy sources, most of the Italian CHP fleet, around 82%, is fueled by natural gas. The role of oil and renewables is negligible, while urban and industrial waste, used as a fuel, cover more than 3%. The rest of CHP plants are driven by residual gases produced as a result of different industrial processes, as hydrogen, refinery gas or blast furnace gas (Figure 58).

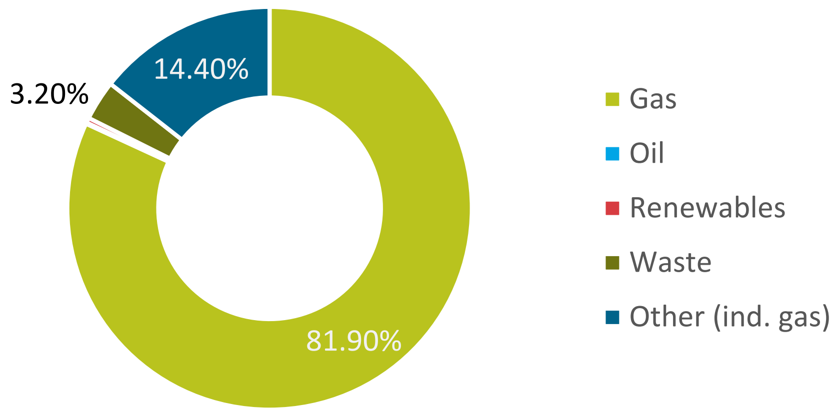

Figure 58. The Italian CHP fleet divided per energy source (installed capacity); data from MSE (2020)

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3.4.2 Regulatory context

The most important elements of the regulatory framework for CHP in Italy is probably the Legislative Decree no. 20 (8 February 2007), which adopts the European CHP Directive of 2004. The Ministerial Decree 4 August 2011 would then define and regulate high-efficiency CHP.

The most common support scheme for CHP in Italy is probably represented by white certificates. The latter represent an energy-efficiency obligation scheme, one of the first to be implemented in Europe, which is still operating. The scheme obliges energy retailers, both for electricity and gas, to fulfil energy efficiency targets, which they can either achieve independently or satisfy through the procurement of white certificates from other parties, who can obtain such certificates through the execution of energy-efficiency measures. The participation of CHP in the white certificate market is regulated through the Ministerial Decree 5 September 2011.

CHP plants that started operation after 2007 obtain white certificates for the energy savings they produce for 10 years. If they are coupled to a district heating network, the time is extended to 15 years. The recent evolution of the price of Italian white certificates is shown in Figure 59. CHP power plants driven by gas also benefit from tax exemptions on the procurement of natural gas (GSE, 2019).

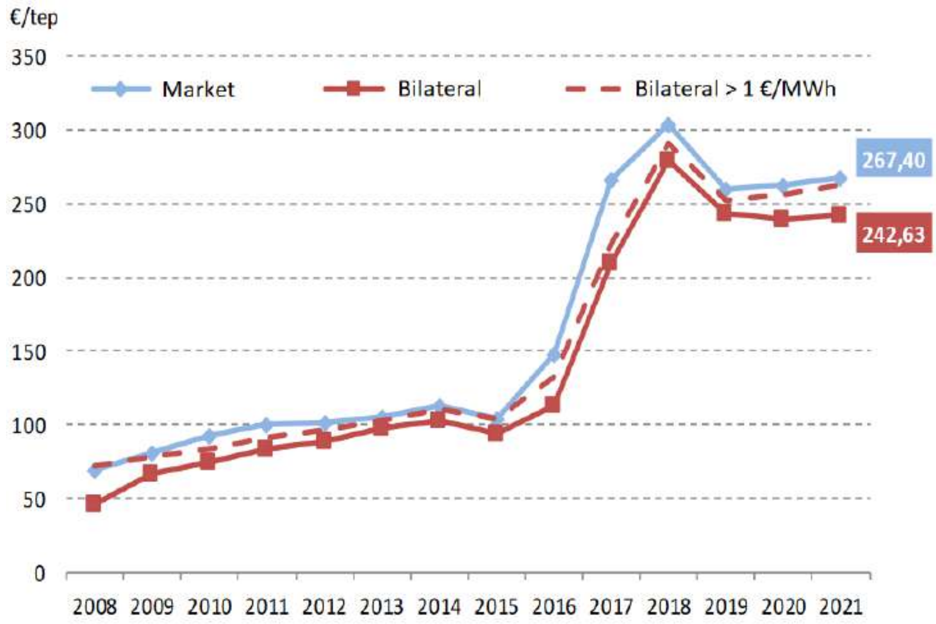

Figure 59. Evolution of white certificate price in Italy; chart from GSE (2021)

3.4.3 Participation in the electricity market

The Italian electricity market is composed by a day-ahead market (*mercato del giorno prima*), an intraday market (*mercato intradiario*), and a balancing market (*mercato dei servizi di dispacciamento*). The first two are run by the market operator, while the latter is operated by Terna, the Italian TSO. The functioning of these markets is very similar to the one already presented for Sweden and Spain in sections 3.1 and 3.2 and, therefore, will not repeated here. As in Sweden, the electricity market has a zonal clearing, meaning that different prices are computed for different zones of the electricity grid, internalising network constraints. These zonal prices are paid to selling offers, while demand is

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exposed to a uniform price, the so-called unique national price (*Prezzo Unico Nazionale*, or PUN, in Italian).

CHP takes part in the electricity market, but it still benefits from priority dispatch. CHP units with an installed capacity lower than 200 kW can also benefit from the Italian net-billing scheme, called *scambio sul posto*.

3.4.4 Participation in the heating market

Italy has a growing district heating sector, whose expansion accelerated from 2005 to 2015, before slightly slowing down in the last years. Currently, more than 4 000 km of heat networks are found in Italy, serving almost 5 000 m^3 of volume, as shown in Figure 60.

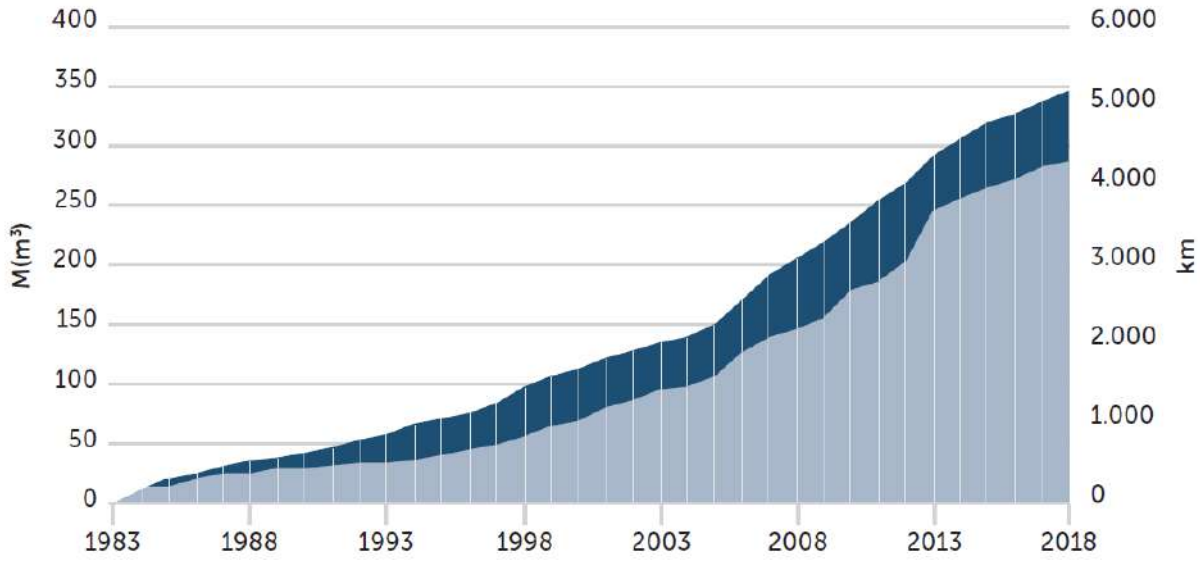

Figure 60. Evolution of the district heating sector in Italy, in terms of volume of served volume (dark blue, left axis) and network length (light blue, right axis); chart from ARERA (2019)

Most of the heat networks are located in the Northern part of the country, especially in Lombardy and Piedmont, as shown in Figure 61.

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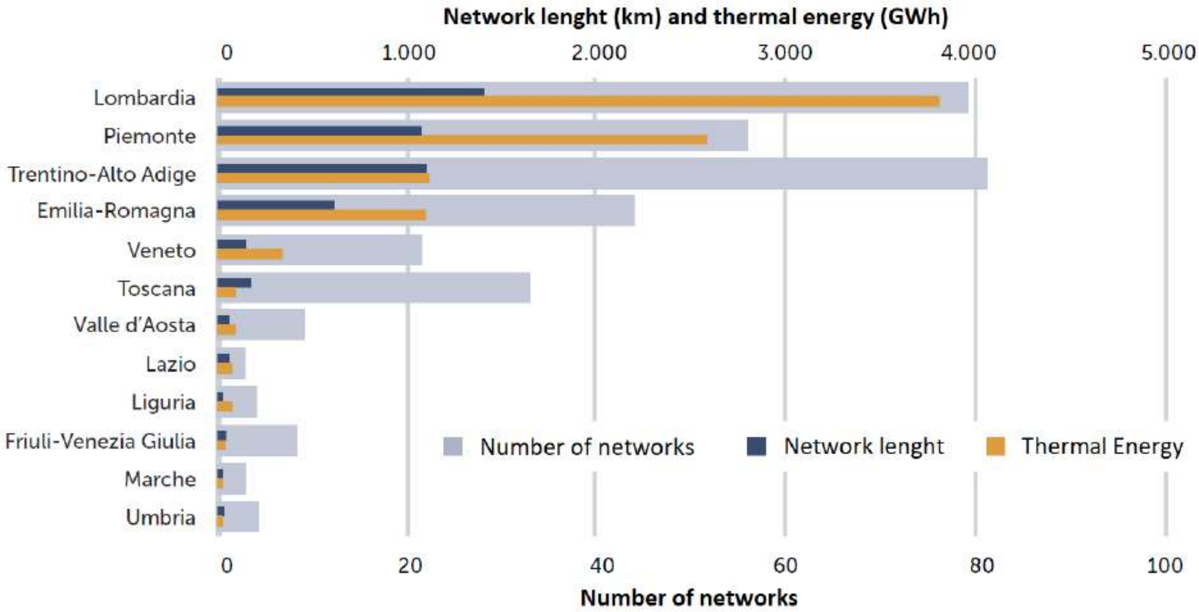

Figure 61. Geographical distribution of heating networks; chart from ARERA (2019)

Only 67.6% of district heating networks are coupled to combined heat and power. The rest of heating networks rely on a heat-only production or on direct renewable energy. In terms of fuels, 69.4% of the network run on natural gas, 15.1% uses waste as a fuel, and almost 10% are driven by bioenergy. There is also a 1.3% of heating network that exploit geothermal energy (ARERA, 2020)

The demand served by heating networks is predominantly residential (63.9%) and commercial (33.2%), while industrial demand covers less than 3% of the energy. The subdivision among final uses is presented in Figure 62.

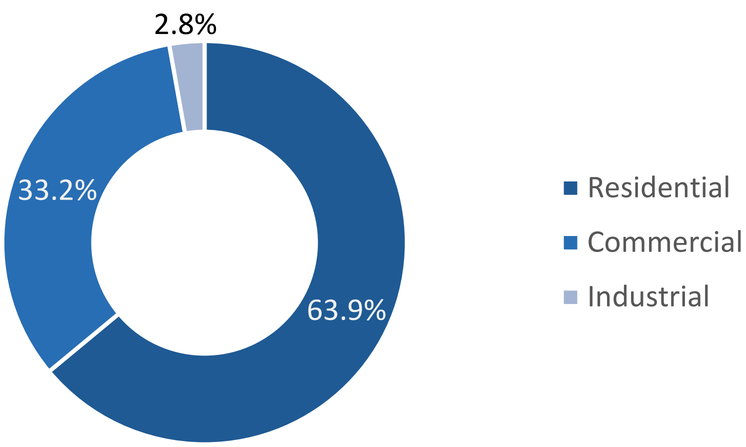

Figure 62. Demand served by Italian heating networks; data from ARERA (2019)

Italy applies a light-handed regulation on the district heating sector. Tariffs are set independently by network operators. Some of them apply a cost-plus approach (especially when the network is operated by a cooperative of consumers), while others set their tariffs based on the opportunity cost of

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consumers (which depends on the alternative they have for space heating). Network operators can also use different tariff structures, with different combinations of fixed and variable charges.

However, the sector is supervised by the National Regulatory Authority, who ensures some level of transparency on prices and controls the compliance with technical and service-quality standards. According to a recent review, a large volatility exists in the tariffs charged by different operators, as shown in Figure 63.

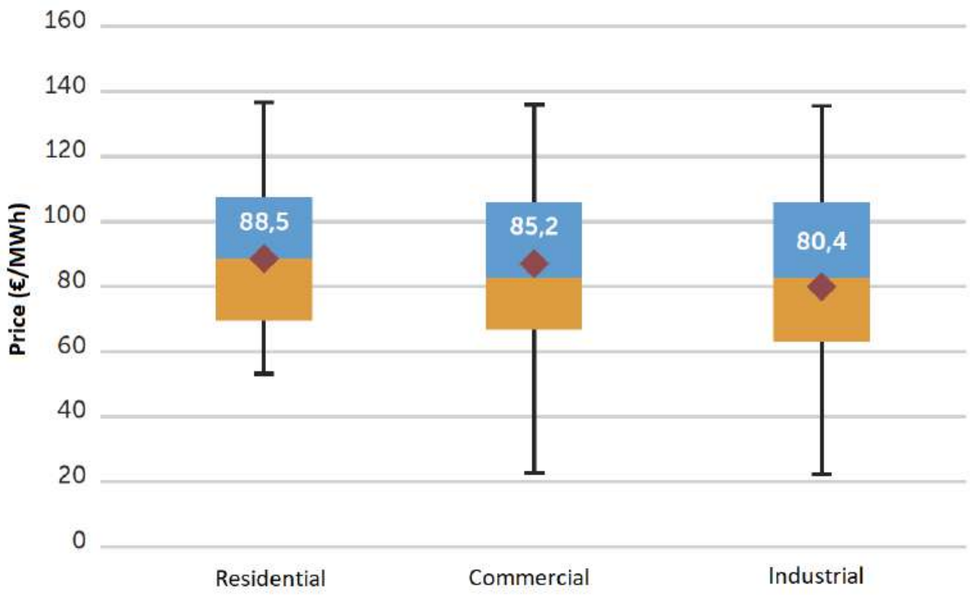

Figure 63. Price ranges for different demands in Italian heating networks; chart from ARERA (2020)

3.4.5 Other issues

Recently, the Italian association of cogeneration operators have released an assessment of the market opportunities for the future. Three scenarios are considered. In the business-as-usual scenario, investments register a slow increase until 2025. In the optimistic scenario, the expansion of the sector is much faster. In the constrained scenario, there is a regression of new investments.

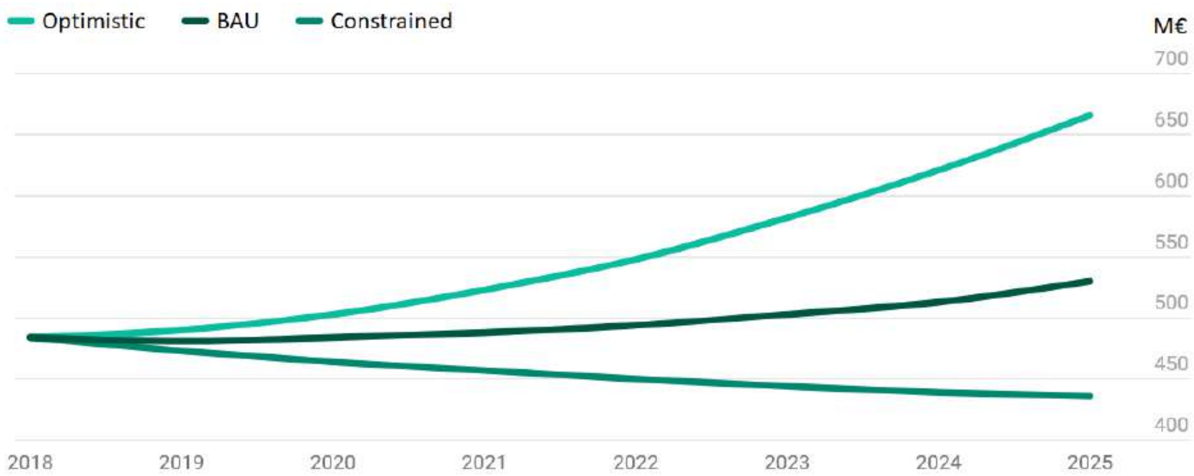

Figure 64. Different scenarios for investments in CHP in Italy; chart from Anima (2021)

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According to the assessment, most of the uncertainty concerns the regulatory environment. In the next few years, Italy should open the balancing market to most of the CHP fleet, reform the white certificate scheme and issue a new regulation on energy-intensive consumers. Another factor that will have a strong influence on the deployment of new investment is the further development of district heating networks, which may foster new CHP projects.

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