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Preface

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Abstrakt/Abstract

The electrification of industry is driven by the rapidly decreasing price of renewable electricity, together with the need for deep decarbonisation. Electricity can replace fossil fuels in most industrial processes. An important aspect of making electricity attractive to industry is the price, and several of the recently formulated industrial road maps identify access to competitive priced electricity as a key component in a future industrial climate policy. First, we present an analysis of the electricity prices paid by European industries, and the way in which they have been affected by climate and energy policy during the past 10 years. After that, we also discuss the possible interplay between a future electricity system dominated by renewables and industry and the need for infrastructure development. The combined effect of policy interventions over the past 10 years has reduced the cost of electricity for energy-intensive industries and helped to maintain the electricity cost at an internationally comparable level. The cost of the transition to renewables has been borne by smaller electricity consumers. In the future, industry can play a major and more active role on the electricity market through demand response, sector coupling and storage options. This can be enabled by a concerted effort to repurpose old and develop new infrastructures. The way in which policy is designed will have considerable influence on who bears the cost of this development, and thus on the development of industrial electricity demand and integration.

Nyckelord/Keywords

Industrial electrification, electricity prices, energy policy, energy taxation, industrial policy

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Content

Executive summary

Electricity can replace fossil fuels in most industrial processes for supplying heat at different temperature levels (Power-to-Heat). Electricity can be used to replace fuels and feedstock or fossil origin in refineries and petrochemical clusters via Power-to-Hydrogen and Power-to-Chemicals route. Currently, there is a strong momentum for electrifying industry driven by the rapidly decreasing price of renewable electricity and the need for deep decarbonisation. Several of the recently formulated industrial road maps identify access to electricity at competitive prices as a key component in a future industrial policy.

In this report we first present an analysis of the electricity prices paid by European industries, and the way in which the electricity prices have been affected by climate and energy policy for the past 10 years. After that, we discuss the interplay between a renewable electricity system and industry, and the need for infrastructure development to enable this.

During the past 10 years, EU climate and energy policies have added both carbon costs and costs for the specific support given to the growth of renewables. The carbon costs, implemented via the EU ETS, have increased the wholesale market price whereas the renewable levies have reduced the wholesale market price but added a cost off market to be paid separately as a levy or fee. Despite the fact that the total costs for the electricity system have increased, the energy intensive industries (EIIs) have been able to enjoy relatively stable electricity prices at an internationally comparable level the past 10 years. EIIs have been exempted from the renewable levies at the same time as the carbon costs due to EU ETS have remained low. The cost of the transition to renewables has instead been borne by smaller electricity consumers such as households and smaller industries that were not exempted from these levies. Consequently, the downward price effect of introducing renewables has been similar or greater than the upward effect of putting a price on carbon emissions. As an example, in the cases of Germany and Sweden in 2015, the price reducing effect of the subsidies to renewables was estimated to be about 10 and 4 €/MWh, respectively. This can be compared with the effect of the carbon cost, which was estimated to increase the price by 4.4 and 4.9 €/MWh in 2015 in these two countries. Thus, the combined effects of EU's climate and energy policies, together with the exemptions from levies and fees, have supported a competitive electricity price to the advantage of industry.

However, it will not be possible to continue current practices as there is increasing pressure to phase out the specific support schemes for renewable electricity production and to rebalance EU's climate and energy policy towards a higher carbon price via the EU ETS and less subsidies to renewables. A higher carbon price and less subsidies to renewables will lead to higher prices on the electricity market for industry but could still promote a continued electrification of industry as the fossil alternatives would become even more expensive as a result of increasing carbon costs. The production cost of renewable electricity has reached a price level which is not substantially higher compared to the average electricity prices of the past 10 years.

For supporting a continued electrification of industry in a high carbon price future, the main barrier will not be the electricity price but access to electricity via distribution and transmission grids. Industrial electrification cannot expand relying on current infrastructures and there is a clear need for new infrastructure that will enable both large-scale electrification and sector coupling to gas grids (hydrogen/methane) that will become a key component in a close to 100% renewable electricity system. Greater integration and sector coupling can be enabled by a concerted effort to both repurpose old natural gas infrastructure and to develop new infrastructures for hydrogen. The EU has recently started to plan for the infrastructure needs for an electrified industry but much more needs to be done. From an industry perspective, the allocation of infrastructure costs, as well as the timing and planning foresight, will be key parameters to consider.

The electricity system can be expected to undergo a rapid transition during the next 20 years becoming much more reliant on intermittent renewables. A strategy for the long-term electrification of EIIs must take into account the fact that this transition must co-evolve with the changes necessary to achieve a renewable electricity system. Industry can play a major and more active role on the electricity market through demand response, sector coupling and storage options. The electricity market regime is currently being developed within the

EU to better support flexibility. The way in which these market regimes are designed will have considerable influence on who bears the cost of this development, and thus on the development of industrial energy demand and integration.

1. 1. Introduction

The major drivers of increased electrification in the industrial sector have been identified as the urgent need to address climate change, the recent rapid decrease in the price of renewable electricity, and the increased focus on digitalization and quality demands (Mai et al. 2018, Lechtenböhmer et al. 2016). Several electro-thermal options were developed during the early 1980s in the aftermath of the second oil crisis in 1979, when electricity prices were relatively low compared to the high price of oil. Fossil energy prices declined in the late 1980s, leading to a significant decrease in the interest in electrification (EPRI 2009). Oil prices have been rising since 2007 and are predicted to continue to increase if future carbon pricing is considered.

Carbon Capture and Storage (CCS) and the use of biomass have been the main options for deep decarbonisation[1] in Energy-Intensive Industries (EIIs), but a marked shift towards renewable electricity has been seen in recent years (IRENA 2019). Electricity is perceived as becoming a key industrial energy carrier in the future if we are to meet the ambitious CO_2 reduction targets demanded by the Paris Agreement (IRENA 2019, IEA 2019). Harnessing the potential of renewable electricity will require new investments, not only in power generation, but also in transmission and distribution networks. The electrification of industry is also highlighted in the EU's long-term strategy (EU COM 2018a). Renewable electricity has the potential to replace coal, oil and natural gas as a fossil-free energy carrier for both high- and low- temperature processes, for example, in the steel, cement, paper and pulp, and glass industries. Renewable electricity can also be used to produce hydrogen via water electrolysis which can be further processed and even combined with captured biogenic CO_2 to produce fossil-free feedstock and fuels.

A key factor determining whether renewable electricity will replace fossil energy in industrial applications is the purchase price relative to that of fossil fuels, and, in a long-term climate perspective, also relative to other low-carbon options. The development of electricity prices paid by industry in the EU and competing countries has recently been

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[1] "Deep decarbonisation" here means reducing GHG emissions to as close to zero as possible, in line with the long-term objectives (> 2050) of the Paris Agreement.

reviewed and analysed in a number of studies (CEPS and Ecofys 2019, Matthes 2017, Fraunhofer and Ecofys 2015). However, there has been no attempt to analyse how the combined energy and climate policy influences the electricity price and how it can be linked to the emerging industrial electrification strategy. Key EU policy documents call for competitive and stable electricity prices for industry (EU COM 2018b, EU COM 2019a, EU COM 2020c), but no suggestions have been made about how this might be accomplished. The actual cost of electricity for industrial users is strongly dependent on policy interventions. Direct effects include exemption from taxes and levies, but policy also has an indirect effect on the electricity market via the EU Emissions Trading Scheme (EU ETS) and subsidies on renewable electricity generation.

The aim of this report was to review how the major energy and climate policies in the EU have influenced the electricity price paid by industry in the past, and to analyse and discuss how future market regimes and infrastructures can develop for an electrified industrial sector.

We start by reviewing the technical options available for electrification, how the electricity market functions, and how the price paid by industry for electricity interacts with the various policies in the EU. In Section 4, we analyse the development of the price of electricity during the past 10 years and the way in which this development is linked to various policy interventions. In Section 5, we discuss the rationale for selectively favouring the electrification of industry, and the ways in which the future industrial electricity demand might change and co-evolve with an emerging renewable power system. We conclude in Section 6. We consider the EU in this paper, but use Germany and Sweden as specific cases to illustrate the variety of policies implemented and their effects.

2. Electrifying industry

In the EU around 80% of fossil CO_2 emissions from manufacturing processes result from the production of non-metallic mineral products (mainly cement), basic metals, refined petroleum products and chemicals (Eurostat 2019a). At the same time, the major share of the energy demand (66% in the EU) and related emissions are associated with the demand for process heating of furnaces, as well as for steam and hot water production (IFC 2015). Furthermore, 23% of the emissions are process-related emissions such as coke production for steel-making, calcination of lime clinker and the depletion of inert anodes for aluminium (*ibid*).

Electrification can replace traditional heating options based on fossil energy via a range of electro-thermal technologies such as heat pumps, electric steam boilers, microwaves, plasma burners and induction heating. Furthermore, hydrogen from electrolysis can be used directly or further processed to produce electro-fuels and electro-feedstock. Shifting from fossil fuels to renewable electricity in industrial processes has the potential to reduce the emissions from industry to essentially zero (Bataille et al. 2017, Kerimidas et al. 2020, Wei et al. 2019, Paige 2017). Very low levels of emission could also be achieved by partial electrification in combination with CCS or increased use of bioenergy. Table 1 provides an overview of specific characteristics of different industrial sectors together with possible electrification options. The electrification options are structured according to whether they can be implemented in existing sites (brownfield investments) or if these option mainly are applicable to new sites (greenfield investments).

Table 1: **Electrification options for different industrial sectors (Based on EPRI 2019, EPRI 2018, Mai et al. 2018, and Lechtenböhmer et al. 2016, DECHEMA 2017, BZE 2018)**

Industry	Transportation fuels, chemicals and petrochemicals	Cement	Iron and steel, glass	Pulp and paper
Specific characteristics	(i) Many different products and processes, at a wide range of operating temperatures (ii) High energy demand for steam cracking (850°C) and steam methane reforming (450-950°C) (iii) High demand for hydrogen (iv) Distillation for thermal separation widespread	High-temperature heat demand for kiln (1450°C)	High-temperature heat demand (1400°C)	(i) Low- to medium-temperature heat demand (<500°C) (ii) Black liquor (biogenic) is combusted for steam and power generation (iii) Drying and evaporation require considerable amounts of energy
Brownfield electrification options	(i) Low-temperature heat pumps (<100°C) (ii) Mechanical vapour recompression (iii) Electric steam generation	(i)Electrolysis and synthetic fuel production from CO_2 flue gases in industrial symbiosis options		(i) Low-temperature heat pumps (ii) Electric steam generation (iii) Electro-thermal processes (e.g. microwaves for drying) (iv) Membrane separation
Greenfield electrification options	(i) High-temperature heat pumps (ii) High-temperature furnaces (ii) Hydrogen from electrolysis (iii) Production of chemicals (via water electrolysis), e.g. ammonia and methanol (iv) Membrane separation	(i) Electrification of heat with industrial-scale electric cement kilns (plasma technology) (ii) Microwave-assisted technologies	(i) Plasma burners (ii) Electrowinning and hydrogen-based direct reduction steel making (iii) Plasma heating and direct electric heating	(i) Production of electro-fuels (ii) High-temperature heat pumps

Emissions resulting from fuel combustion for process heating are high and vary considerably between different industries. In chemical and petrochemical processes, there is a demand for low- (<250°C) and medium- (250 to 600°C) temperature heat, mainly in the form of steam for process heating. In contrast, high temperatures (>600 to 1450°C) are required for heating in the production of cement, steel, glass and other metals and minerals but also for steam cracking and steam methane reforming in chemical and petrochemical processes. In the pulp and paper industry and smaller manufacturing and food industries the demand is mainly for low-temperature heat.

The potential for the electrification of a process varies depending on whether it is a brownfield or greenfield investment. The installation of heat pumps at existing processing plants (brownfield investments) will lead to a gradual increase in electricity demand and a decrease in boiler fuel demand. It should be noted that the potential for the electrification of individual plants varies considerably since the processes are very different. In particular, chemical, petrochemical, and pulp and paper plants are highly complex, with many interactions between process units and different degrees of integration. Changing the energy carrier of a unit operation to electricity will most likely lead to cascade effects that must be considered (Wiertzema et al. 2018). For example, switching from steam turbines to electric motors to run pumps and compressors in an oil refinery can lead to an excess of low-value by-products that were previously used as boiler fuel. Thus, each industrial plant must be analysed individually to assess the impact of electrification. The situation is different for greenfield investments since the degree of electrification is not limited by the existing process. Including electrification in the initial process design can lead to a substantially higher electricity demand, but much lower greenhouse gas emissions compared to retrofitting an existing plant (e.g. using electrolysis instead of methane steam reforming for hydrogen production).

Barriers associated with the implementation of electrification options include technology availability, investment costs and the operating costs, compared to traditional fossil options. Several electro-thermal technologies, such as conventional heat pumps and electric steam generators, are readily available. Other technologies, such as plasma burners for high-temperature applications or electro-heating, have not yet been developed for industrial use, and their applicability must be verified in each specific industrial setting through pilot-plant and demonstration projects. A specific barrier to electrification of the pulp and paper industry is that the emissions are to a large degree biogenic, leading to a lower incentive for electrification under current carbon reduction policy regimes.

3. The electricity market regime and climate and energy policies

The electricity supply market is a combination of a wholesale market for trading electric energy (in kWhs) and a transmission and distribution "market" where costs are determined as in a regulated natural monopoly. The market regime also includes balancing and reserve markets to maintain grid stability and deliver sufficient power. Furthermore, renewable electricity policies have created separate "investment markets" for renewables via quotas or feed-in tariffs.

3.1 The wholesale market for electricity

The wholesale markets for electricity were deregulated in the EU during the 1990s, and now include spot markets (day-ahead and intraday) and futures markets. On a free market, the long-term average price will, theoretically, converge towards the cost of the last-added power capacity in the system, e.g. the long-run marginal cost or "build margin" cost (Joskow 2007), whereas short-term price fluctuations determine the dispatch merit order between existing power sources (the short-run marginal cost). However, the market is not entirely free, and the actual investments in new power capacities are strongly influenced by policies.

In the EU, the combined climate and energy policy includes both a climate target and a specific renewable electricity target, and thus has a major influence on the wholesale price of electricity. The climate target is implemented via the EU ETS, which ensures that CO_2 emissions remain under the predefined cap, and that the cap target is met at the lowest marginal carbon abatement price. The targets for renewable electricity are defined by an EU directive (EU COM 2011) but are implemented nationally, with variations in certificate schemes, quotas and feed-in-tariffs across the EU. Both the EU ETS and the renewable electricity targets influence the price of electricity on the wholesale market.

The EU ETS has a direct influence on the wholesale market price of electricity as it adds an extra cost (the EUA[2] price) to fossil electricity production. The price increase depends on the emission intensity (g_CO_2/kWh*)* of the electricity that is actually produced on the margin, which is normally gas power during peak loads and coal power during non-peak loads.

[2] EUA: European Union Emission Allowance; the trade emission commodity in the EU ETS.

Production of 1 MWh of coal power emits roughly 0.9 tonnes of CO_2 and 1 MWh of gas power roughly 0.45 tonnes of CO_2. The proportion of the extra EUA cost that is passed on to the wholesale price depends on the market structure and how competitive the market is. Results from econometric studies vary depending on the methods used and the timeframe studied, but suggest that the extra cost arising from the EUA is around 70 to 85% of the *average* added EUA cost (Sijms et al. 2008, Fabra and Reguant 2014), whereas the hourly cost pass-through may vary significantly more (Huisman and Kilic 2015, Hintermann 2016).

The price of electricity on the wholesale power market has decreased as a consequence of the introduction of renewable electricity. The policies targeting renewable electricity have had two distinct effects on the market. Firstly, the way in which renewable policies have been implemented has created a separate investment market for renewables, which has had an indirect effect on the wholesale market by by-passing the ordinary market. Investment decisions are no longer based on the expected average long-term marginal cost, but instead on the subsidy received “off-market” (Finon 2013). Secondly, there is a merit order effect due to renewables having close to zero marginal costs and priority as “must runs” in daily operation, which shifts the merit order of the power system and lowers the marginal cost (Sensfuss et al. 2008, Cludius et al. 2014). In an econometric study, Breitschopf et al. (2016) estimated that a 1% increase in renewable electricity supply would reduce prices by, on average, 0.4 euros/MWh in the EU, and between 0.6 and 0.8 euros/MWh in Northern Europe.

3.2 The regulated monopolies for transmission and distribution

The cost of transmission and distribution constitutes a major part of the total price of electricity paid by the end-user (around a third of the total cost for households, and 10 to 20% for industrial customers). The transmission and distribution of power is, by definition, a regulated natural monopoly and, as such, the price of this service is based on various cost recovery schemes, rather than being determined by a market (Sine and David 2003). The cost of transmission lines, which form the backbone of the power system, is in principle shared by the entire electricity user collective. In the case of distribution grids, the customers that are served by that specific part of the grid share the costs.

Industry can usually by-pass the low-voltage distribution grid and connect directly to higher-voltage regional grids, resulting in a cost that is substantially lower than that for household customers. Lower grid fees are offered to certain Energy-Intensive Industries (EIIs) as their electricity use is predictable, which reduces the cost for the grid owner (PwC 2017). When a new major power-consuming industrial plant is added to the power system, the principle is that the specific company must cover the cost of upgrading the power system required to handle this new load. The cost of connecting new renewable electricity to the grid should, in principle, be paid by all power consumers collectively. However, in some countries, for example, in Germany, energy-intensive industries have been exempted from extra transmission costs arising from the investments in e.g. off-shore wind parks (PwC 2017).

Balance is maintained in the grid through several mechanisms, including the day-ahead market, where the entities responsible for balancing[3] have an incentive to match consumption with production of electricity as well as possible. There are also various dedicated "off-market" flexibility mechanisms whereby EIIs can offer to reduce or increase their power consumption in exchange for a fee. In a recent study by CEPS and Ecofys (2018), all primary aluminium producers and >70% of Electric Arc Furnace (EAF) steel producers participating in the study stated that they took part in a flexibility market scheme. For secondary aluminium, refineries, nitrogen and primary steel production, less than 25% of the companies were involved in flexibility schemes (CEPS and Ecofys 2018).

[3] Usually the electricity retailer.

4. Electricity prices for industrial users in the EU and the influence of policies

4.1 Electricity prices for industry and households over the past 10 years

Industry is exempted from several taxes and levies, and thus pays substantially less for electricity than household consumers. The first, and most direct, effect of policy on the electricity price paid by industry is the partial exemption of energy taxes. All EU member states exempt EIIs from the relatively high energy taxes paid by households. The EU has defined what constitutes an EII[4], but the definition leaves room for interpretation by member states, and the industries that are exempted thus vary between member states. Policy makers also have the option to exempt EIIs from part of the extra costs of electricity resulting from climate and energy policies. Member states have the legal option to compensate industries for up to 75% of the estimated pass-through costs arising from the EU ETS and to exempt EIIs from paying the levies and fees needed to support the expansion of renewable electricity.

As argued in Section 3, climate policy (the EU ETS) increases the electricity price, whereas subsidising renewable electricity reduces the price. The balance between using a "stick" (carbon pricing) or a "carrot" (renewable subsidies) for decarbonising the electricity sector will thus influence the electricity price on the wholesale market. An option for policy makers that will support industry is thus to decarbonise the EU energy system more by subsidising renewables than putting a price on emission via the EU ETS. Subsidizing renewables could increase the total system cost for the power system but this cost is not necessarily passed through to industrial consumers given the exemptions. Increasing subsidies on renewable electricity "off-market" will benefit industry as long as they are exempted from paying the levies and fees for this transition. Another benefit for industry of balancing the decarbonisation policy more towards subsidies is that, given a fixed EU ETS target, increasing renewable subsides will decrease the price of the EUAs and thus the *wholesale*

[4] Article 17 in EU Directive 2003/96/EC states that an energy-intensive industry for which energy costs constitute at least 3% of the production value or at least 0.5 % of the added value need only pay the minimum tax of 0.5 euros/MWh. Article 4 in the same directive grants total exemption to "electricity used for chemical reduction and in electrolytic and metallurgic processes".

market price of electricity[5]. Increasing the ambition of the EU ETS with a stricter reduction target will lead to higher EUA prices and will increase electricity prices for industry.

Figure 1 shows the price paid by industrial customers with a consumption of 70 to 150 GWh/y from 2007 to 2017. The price includes that of the electricity, its transmission and distribution and taxes and fees but does not include VAT and recoverable taxes. The prices paid by households consuming between 2500 to 5000 kWh/y and households consuming more than 15 000 kWh/y[6] are also shown for comparison.

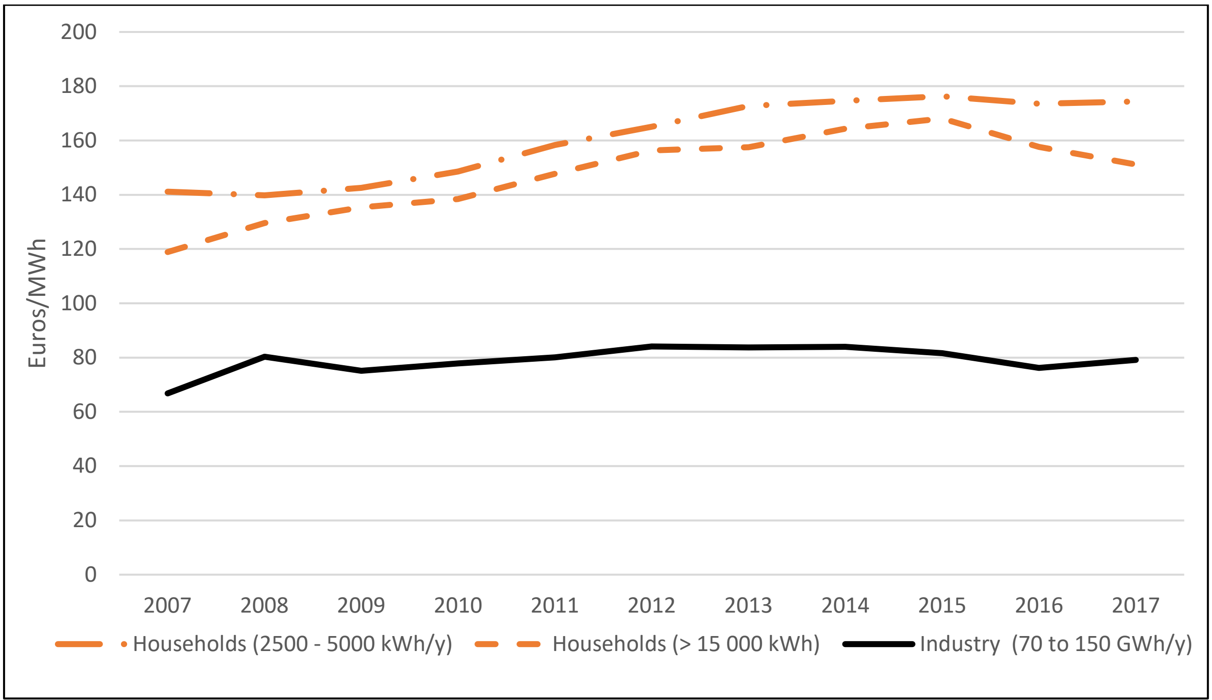

Figure 1. Average Electricity prices paid in the EU by industry and households, including transmission and distribution fees but excluding VAT and recoverable taxes. Industry 70 – 150 GWh/y, Households 2500-5000 kWh/ and households >15 000 kWh/y. (Source: Eurostat 2019b)

It can be seen from Figure 1 that the price of electricity paid by households increased steadily up until 2015. During the period from 2007 to 2017, both EU climate and renewables policies had a major effect on emissions and energy systems. The trend of

[5] In general, subsidies renewable electricity will, at least in the short term, increase the total system cost of the power system compared to only "pricing carbon" which is seen as more cost-efficient from a socio-economic view

[6] In Scandinavia direct electric heating and /or heat pumps are common and households can typically consume this amount of electricity

increased electricity price for households can be explained by increasing costs associated with renewables, paid mostly via levies. The *transitional costs*[7] for renewables (levies and fees) represented 40% of the total electricity cost paid by households in 2017 (compared with 28% in 2008) (Eurostat 2019b). Transmission and distribution costs have also shown a slight increase in absolute values, but the share of the total electricity cost has remained approximately the same for households (30%). The cost of electricity for industry has remained essentially constant, showing even a small decrease since 2014. The difference in the price development for industry and households can be explained by the fact that industries are largely exempt from the cost of introducing renewables, while the increase in price resulting from the EU ETS was only small.

The lowest electricity prices are paid by industries that consume over 150 GWh/y, such as operators of electric arc furnaces and aluminium smelters, and these industries are not included in Figure 1. No comprehensive official statistics are available for this category of industry due to confidentiality. Instead, electricity costs were obtained from a bottom-up study (CEPS and Ecofys 2018) of separate EIIs consuming over 150 GWh/y of electricity and these are shown in Figure 2**.** The examples presented in Figure 2 are based on a total of 47 specific case studies spread across the EU, and while they do not represent a statistical sample, they provide an indication of electricity costs.

[7] *Transitional cost:* the extra cost paid as fees and levies for temporarily subsidizing the development of renewables on the market until they become competitive

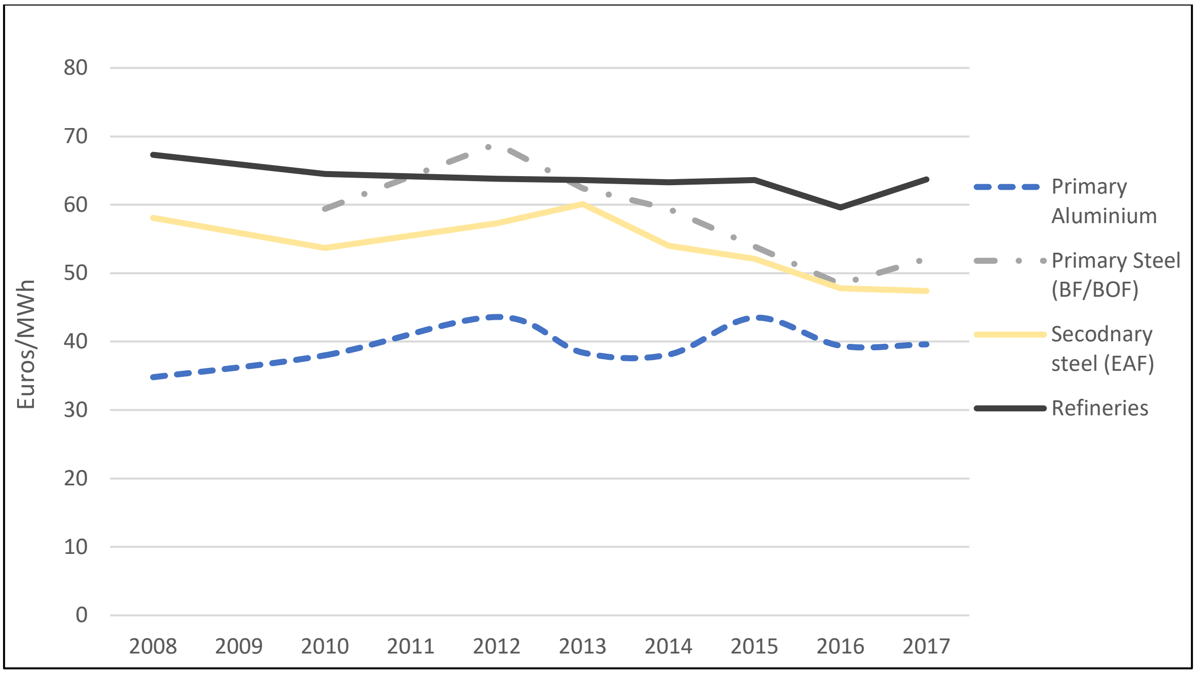

Figure 2. Weighted average of electricity prices between 2008 and 2017 paid by a sample of European industries using on average > 150 GWh/y. Data for primary aluminium are from 9 plants, for secondary steel 18 plants, for primary steel 7, and for refineries 13 plants. (Adapted from CEPS and Ecofys (2018))

As can be seen in Figure 2, the price paid by European industries consuming more than 150 GWh/y is typically between 45 and 65 euros/MWh. The variation in price can mostly be explained by the size of the facility, where large consumers can negotiate better prices and pay lower grid fees. Regional price differences in the wholesale markets can also play a part, but this difference has decreased during recent years due to increased market coupling (EU COM 2019).

All EU member states offer exemptions from taxes and levies for EIIs consuming more than 150 GWh/y. The levels of taxes and levies differ between countries and specific sectors, but are in general low, around 4 to 12% of the total cost of electricity, for industries consuming more than 150 GWh/y (CEPS and Ecofys 2018). Very electricity-intensive industries are usually connected directly to the transmission grid resulting in low grid fees. For example, the EAF steel industries paid on average 7.7 euros/MWh and the primary aluminium industry 3.4 euros/MWh in grid fees in 2017 (CEPS and Ecofys 2018). This can be compared with the EU-average grid fees for industries of 13.6 euros/MWh (Eurostat 2019b).

The findings presented above indicate that industrial electricity prices have remained relatively constant over the past 10 years, and have followed the general development of the wholesale price on the EU spot market. Wholesale electricity prices in the EU decreased slowly between 2008 and 2017, apart from a sharp rise in 2017 following the extreme winter in 2016 (EU COM 2019). EIIs often have a direct purchasing agreement with power producers whereby the price that they pay is based on both the spot market price and the average price on the long-term spot market (CEPS and Ecofys 2018).

4.2 Decomposing the influence of policy on industrial electricity prices – the cases of Sweden and Germany

The degree to which each policy factor affects the price of electricity for industry was decomposed and analysed for the cases of Sweden and Germany. Figures 3 and 4 show the direct effects of tax/levies exemptions and the indirect effects of policy on the wholesale price in Sweden and Germany, respectively.

The direct effects of exemptions from taxes and levies are shown on the right-hand side of the Figures. The indirect effects can only be estimated. To estimate the effect of the EU ETS, we assumed that the yearly average marginal emission intensity was 0.8 tonneCO_2/MWh for both Germany and Sweden, and that the EUA cost pass-through factor was on average 0.8 for Germany and 0.9 for Sweden, based on studies by Fabra and Reguant (2014) and Fell (2010). The average price of an EUA in 2015 was 7.3 euros/tonneCO_2. The yearly average price effect of subsidising renewables in Germany is based on Matthes (2015, 2017) and was estimated for Sweden based on Breitschopf et al. (2016). The “no policy” price on the left of Figures 3 and 4 thus describes the counterfactual prices that would have resulted in the absence of support for renewables and the EU ETS and according to our estimates.

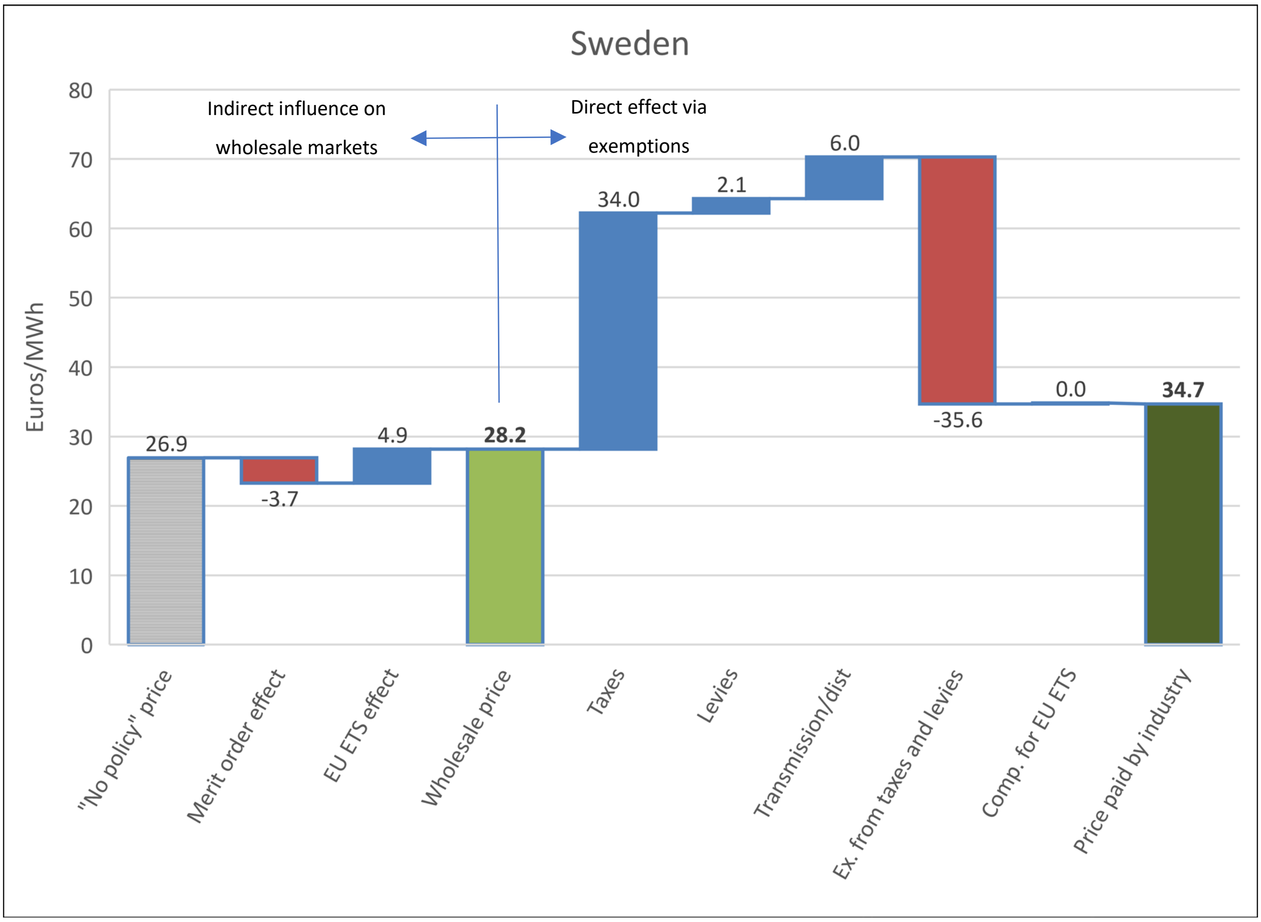

Figure 3. Influence of policies on electricity price paid by industrial users with an annual usage of 70 to 150 GWh/y in Sweden in 2015. (Sources: Own calculations based on Eurostat (2019b) and Breitschopf et al. (2016), and EU COM (2016) for estimates of the merit order effect, and Sijms et al. (2008) and Fell (2010) for estimates of the effects of the EU ETS.

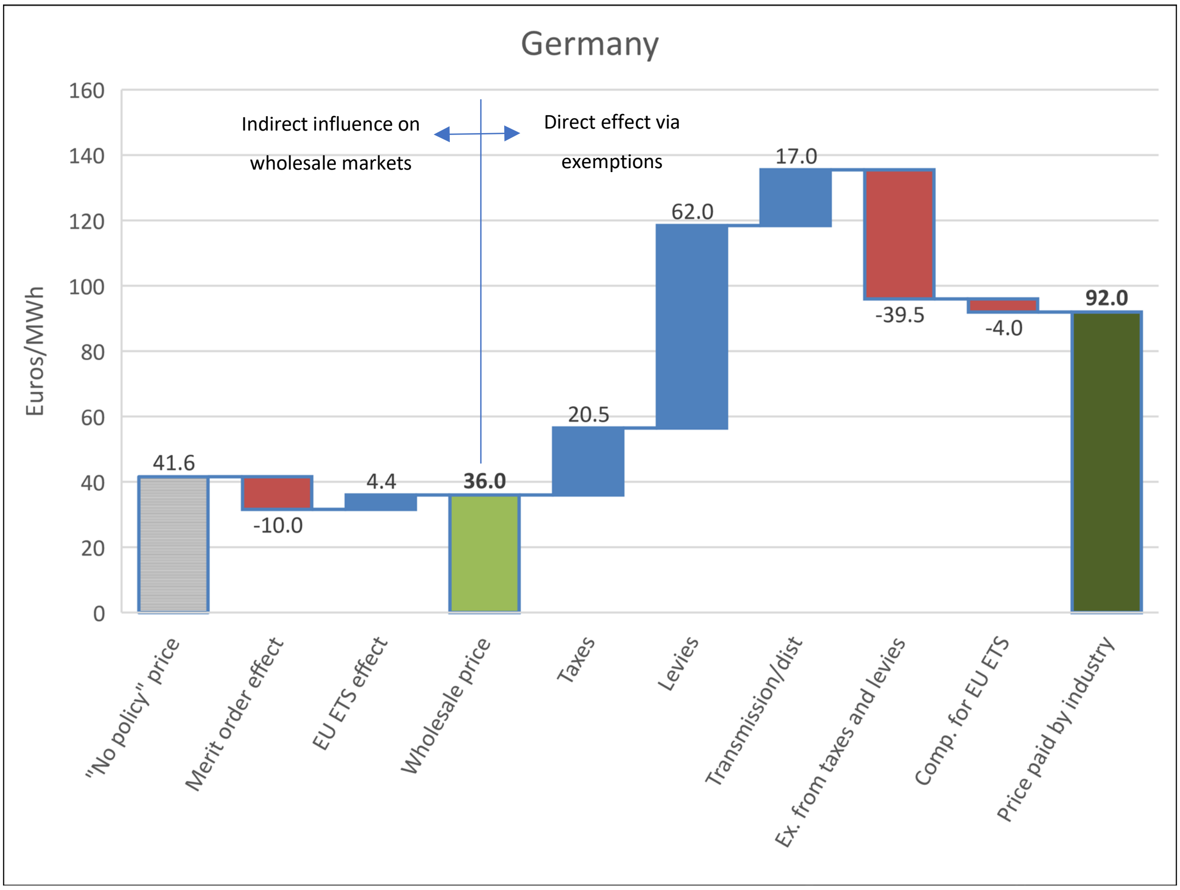

Figure 4. Influence of policies on electricity price paid by industrial users with an annual usage of 70 to 150 GWh/y in Germany in 2015. (Sources: Own calculations based on Eurostat (2019b), Matthes (2015, 2017) for estimates of the merit order effect, and Sijms et al. (2008) and Fabra and Reguant (2014) for estimates of the effects of the EU ETS.)

Exemptions from energy taxes and levies are the policy measures that have the greatest influence on reducing electricity prices to industry. However, exemptions are not uniform across the EU but vary both in scope and size. Comparing Figures 3 and 4, it can be seen that the exemptions from taxes and levies are substantially less for German industries than those in Sweden. This difference between Germany and Sweden is mainly due to the differing definitions of what constitutes an “energy intensive industry” in the category 70 to 150 GWh/y. For EIIs using more than 150 GWh/y, the difference is less.

Germany has adopted a more aggressive renewables policy, which means that the levy paid in Germany, the Erneuerbare-Energien-Gesetz (EEG) surcharge, is substantial. The German EEG tariff for household consumers was 62 euros/MWh in 2015. The Swedish/Norwegian renewables certificate scheme has, in comparison, added a cost to electricity consumers of

2.1 euros/MWh in 2015. Germany grants a partial exemption from the substantial EEG levy[8] for industries that consume 70 to 150 GWh/y, whereas Swedish industrial consumers are completely exempted from paying the cost of buying certificates in the Swedish/Norwegian renewable certificates scheme. However***,*** Germany compensated companies for the price increase due to the EU ETS, whereas Sweden did not[9]. However, as the price of EUAs was low in 2015, this effect was small. Since the revision of the directive in 2019, EUA prices have risen, so the effect will most likely be more pronounced in the future. Germany also has higher grid (transmission and distribution) fees, due partly to their ambitious renewable policy (PwC, 2017). Some exemptions to grid fees have also been granted to large industrial users, and Germany granted exemptions covering part of the grid cost for EIIs, but this had to be paid back as it was found to violate state aid rules[10].

The combined indirect effects of the EU ETS and the subsidies to renewables on the wholesale price of electricity is estimated to be negative in Germany and slightly positive in Sweden. This means that the current wholesale market price is lower than the counterfactual price than would have resulted from "no policy" in Germany, and higher in Sweden. However, this is only a snapshot for the year 2015, and these price effects vary over time. The market price of electricity also depends on several factors that are not directly related to the climate policies analysed here. Hirth (2018) recently performed a thorough decomposition analysis of the spot market prices in Germany and Sweden from 2008 to 2015, and came to the conclusion that the increase in electricity prices due to the phase-out of nuclear power in Germany is roughly compensated by the reduction arising from the subsidies to renewables. The effect of a nuclear power phase-out could also become a reality in Sweden in the future. The first nuclear reactors are currently being phased out based on commercial decisions, and there is a political *ambition* (nuclear energy is not forbidden) to phase out the remaining 6 reactors by 2040. This is, however, currently being debated in Sweden, and the future of nuclear power remains uncertain. Another key

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[8] The "Special Equalisation Scheme" works as follows. The full EEG is levied for the first GWh, but only 15% of the EEG is levied for each subsequent kWh up to a maximum of 4% of the gross output of the company. Companies with a higher electricity intensity (20%) pay a maximum fee of 0.5%.

[9] Compensation schemes have only been implemented in a third of the member states.

[10] http://europa.eu/rapid/press-release_IP-18-3966_en.htm

feature of the Swedish power system is the current surplus production capacity. The downward pressure on electricity prices caused by the merit order effect in Sweden would have been much higher if Sweden had not been able to export its surplus energy to Northern European markets, which has helped Sweden to maintain electricity prices (Hirth 2018).

4.3. Risks and motivations for favouring industrial power consumers

As seen above, industrial users pay substantially less for electricity compared to household consumers in the EU. The risks associated with this price difference are both short and long term. In the short-term, reducing the electricity price will lead to an increase in demand and reduce incentives for energy efficiency. In the long-term, lower electricity prices create an expectation of continued low prices and investment incentives in end-user sectors that can create a societal lock-in to a “high-electricity industry society” (Fouquet 2016).

However, EU policy makers have several reasons for managing electricity prices and for ensuring that they are competitive. The ambition of the EU is to show leadership in climate mitigation without risking that industry loses competitiveness that could result in carbon leakage. The risk of carbon leakage motivates policy interventions for ensuring that electricity prices should not increase as a result of climate policy. This is a strong political reason for exempting EIIs from taxes, renewable levies, and for compensation for the increased electricity prices arising from the EU ETS. These exemptions and compensations are a part of the broader industrial policy of the EU, where especially EIIs producing basic materials (steel, cement, aluminium, plastics, etc.) operate on a global market with few opportunities to differentiate their products or to pass on carbon costs to the end consumer (Åhman et al 2017).

A comparison of international electricity prices for industry indicates that practically all industries in most competing countries pay similar prices for electricity (Fraunhofer and Ecofys 2015, EU COM 2019b). Exemptions from taxes are common globally, and there are even examples of subsidies that reduce the price of electricity below the actual production cost, for example, in rapidly industrializing countries such as China and Brazil (Haley and Haley 2013, Fraunhofer and Ecofys 2015). Most of these rapidly industrializing countries do not have a free market for electricity based on marginal pricing, but instead have an integrated monopoly market based on cost recovery, which provides opportunities for various kinds of subsidies.

5. Electricity market regimes and deep electrification of industry

5.1 The strategic role of electricity in deep decarbonisation

There is a long-term strategic reason for supporting the increased electrification of industry. To achieve the transition to a decarbonised economy, the options available to industry for deep emission reductions are the implementation of CCS, a shift to biomass, and electrification based on renewable fuels or nuclear power (Bataille et al. 2017). From a technical perspective, CCS is a logical solution, but it has suffered from poor economics and public acceptance in the countries where actual investments have been done, resulting in wavering political support and economic uncertainties that have effectively stalled investments (Åhman et al. 2018). Biomass will be needed as partial solution in many industries but the amount of available biomass will be limited if sustainability is to be taken seriously. There is still a major lack of consensus regarding the amount of biomass that can be produced globally under sustainable conditions (Wang et al. 2019) but future competition for the available sustainable biomass resource is likely to drive costs upwards.

The cost of renewable electricity generation has fallen sharply during the past 10 years (>70%), and is projected to continue to decrease. The potential for renewable electricity generation is physically less limited compared to biomass production and/or CCS and is furthermore becoming increasingly competitive compared to fossil alternatives. In many cases, renewable electricity is already competitive today with fossil energy, even without carbon pricing, and is likely to remain so even when options such as off-shore wind power generation are considered (IRENA 2019). All decarbonisation options have specific barriers or limitations, but the expansion of electricity use is currently viewed as a core component for decarbonising the whole economy, and, at the same time, reducing several local pollutants (IRENA 2019).

5.2 Future electricity demand and its interplay with the electricity system

The electricity system in the EU is rapidly switching from fossil fuels to more renewables as a result of strong energy and environmental policies. The share of renewable electricity in the EU is projected to reach 47.3% already by 2030, according to Banja and Jégard (2017), but could exceed 60% due to low renewable electricity generation costs simply outcompeting those of coal and gas (Artelys 2017). The EU COM estimates that the current climate ambitions of the EU will push the power sector to reduce its CO_2 emissions by more than 80% by 2050 and will thus become dependent on more than 70% of renewable solar or wind power (EU COM 2018b).

The electrification of industry as a climate option depends on the expansion of electricity from renewable resources. In a theoretical scenario presented by Lechtenböhmer et al. (2016), in which it was assumed that all industry in the EU will eventually be electrified, it was predicted that the electricity use in industry would increase to over 1700 TWh/y, which should be compared with the current industrial use of 125 TWh/y. This scenario was based on the assumption that the industrial production volumes of steel, aluminium and basic chemicals would remain the same up to 2050. Most of the increase results from replacing fossil feedstock for the production of chemicals with renewable feedstock produced by combining CO_2 with hydrogen produced through electrolysis of water (>1200 TWh/y). Steel manufacture is also a large potential electricity consumer (>250 TWh/y, due to large-scale implementation of electrowinning) (ibid). This high predicted increase in the demand for electricity raises the question of future available supply. However, Longa et al. (2018) estimated that the potential *theoretical* supply in the EU27 in 2050 would be 5300 to 26 000 TWh/y from wind power alone (both on- and off-shore), and thus realising only part of this potential would be sufficient.

The increase in renewable non-dispatchable electricity generation will require a more flexible power system. The current EU power system is able to integrate up to 40 to 50% renewable electricity within the current market regime by activating the existing flexibility options in the system (Papaefthymiou and Draggon 2016). However, the need for flexibility increases rapidly at levels above 70 to 80 %of non-dispatchable renewables in the system, especially on longer time scales (weekly and seasonal storage) (ibid). This will create a market for both demand response and for storage options on different time scales. For example, Kondziella and Bruckner (2016) estimated that in a 100% renewable electricity system, up to 40% of the total electricity demand must be supplied via flexibility measures (storage or demand response). Hydrogen for enabling sector coupling and the infrastructure development are discussed below.

5.3 The crucial role of hydrogen in a future renewable electricity system

In a deep electrification scenario for industry where several greenfield electrification options become available, the current fossil feedstock for transportation fuels and petrochemicals would be replaced by methane produced from renewable electricity and CO_2. Hydrogen, produced from electrolysis of water with renewable electricity, is expected to increase substantially as an industrial energy carrier/feedstock in most deep decarbonisation scenarios for 2050. Hydrogen can be stored and can also increase the exchange of energy between sectors using a common energy carrier (transport- energy-industry-housing), so called "sector coupling".

In 2018, the EU commission outlined 8 different long term scenarios for the power sector in their key policy document, "A Clean Planet for All" (EU COM 2018b). In their "decarbonisation 2050" scenario, 81% of the electricity produced in the EU would be renewable. The remaining 19% would be covered by nuclear and some residual fossil energy with CCS. (ibid, page 75). Hydrogen and "e-fuels" play a crucial role in these scenarios by providing between 65 and 220 TWh/y of chemical storage (EU COM 2018b, pp 80). Electrolysers, transforming renewable electricity and water into hydrogen, are a key technology in a hydrogen society and the EU hydrogen strategy (EU COM 2020b) has recently set a target of introducing 6 GW of electrolyser capacity by 2024 that should increase to 40 GW by 2040[11]. The EU hydrogen industry has made an even more rapid/ambitious scenario in which they assume 40 GW by 2030 and another 40 GW of electrolyser capacity in neighbouring countries from which EU can import hydrogen (FCH 2019). In the scenario presented by Lechtenböhmer et al. (2016), the replacement of crude oil as feedstock for production of petrochemicals and fuels represents the major increase in hydrogen and e-fuels use with a total of 778 TWh/y assuming that production levels of petrochemicals in 2050 will be similar to levels of 2010. The scenarios defined by the EU COM (2018b) only look at e-fuels for transport and not for replacing crude oil as feedstock.

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[11] 40 GW electrolyser will produce 200 TWh of hydrogen assuming run at 80% capacity and 70 % efficiency

Hydrogen offers a great potential for industrial demand response with long duration which is the most crucial future demand response needed when the power system is dominated by seasonal fluctuating renewables. Electricity storage with durations ranging from minutes up to a day can be covered by e.g. batteries, flywheels and thermal load shifting in industry. However, when storage demands with a weekly or monthly duration are needed to maintain system balance then these can only be covered by PtX (power-to–X) solutions and by industrial load *shedding*[12]. Hydrogen can easily be stored either in gas pipelines or in relatively inexpensive underground storage (e.g. lined rock cavern). When industry produces hydrogen for internal use, with an overinvestment in electrolysis capacity and access to gas-storage, industry can offer substantial demand response by reducing hydrogen production and instead using the stored gas. Furthermore, with access to gas storage, gas-turbines that run on hydrogen can be used for supporting power production if needed.

5.4 Infrastructure for connecting consumption and production

Access to the amount of electricity required at the right time will be a challenge as new electricity-intensive industries emerge and existing industrial sites are electrified. Sufficient production of renewable electricity is of course important but a more relevant and strategic question is whether it is possible to transmit and distribute these vast amounts of renewable electricity to industry, and whether it is possible to ensure sufficient quality of the delivery in the power grid. The geography of consumption and production will change with increasing demand to new locations and a more decentralised power production structure while old centralised facilities will be abandoned. Industrial electrification will thus lead to substantial increases in the need for investments in grid infrastructure which must be developed rapidly in order to keep up with the changing geography of electricity production and consumption in Europe (ENTSO-E 2019).

[12] Load shedding: Reducing industrial output permanently which can be a very expensive and unwanted option (Paulus and Borggrefe 2011)

Wuppertal Institute (2020) made a first brief analysis of infrastructure needs if EU industry is electrified (see also Merten et al. 2020), based on a scenario developed for the EU COM by Materials Economics (Materials Economics 2018). They concluded that current infrastructure planning, as done by ENTSO-E[13] and within national planning, needs to include high electrification scenarios and to adopt a longer time perspective (beyond 2030) in order to be effective (EU COM 2020a). Especially the need to integrated planning cross-sectional to enable sector coupling is needed.

It is argued that 5 to 15% of hydrogen can be blended into the existing natural gas grid without major investments (EU COM 2020b). However, the current users of natural gas often rely on a specific quality making this difficult. In a longer-term zero emission scenario with declining natural gas demand, there is an opportunity to repurpose parts of the existing natural gas infrastructure into a hydrogen grid (EU COM 2020b). As an example, EU COM (2020b) claims that 90% of Germany´s future hydrogen need can be distributed in repurposed old natural gas lines. Several of the industrial clusters in EU are already connected with gas pipelines to strategic ports. However, in practice this might be difficult in a transitional phase when there would be a need to mix hydrogen and natural gas.

If access to renewable electricity becomes a barrier for decarbonisation of EIIs in some “hot spots” in the EU, one option will be to import intermediates such as ammonia, DRI or HBI[14] and synthetic fuels (e-fuels) instead of producing them within the EU. Downstream processing and refining doesn´t always have to be integrated to the upstream energy intensive part of e.g. reducing iron ore to pig iron or cracking crude to ethylene. Gielen et al. (2020) make the case for an Australian shift from exporting iron ore to exporting DRI (sponge iron) based on renewable electricity instead. Renewable ammonia or hydrogen as feedstock for fertilizers and petrochemicals can also be a future commodity. Gidey et al. (2017) and Armijo and Philibert (2019) argue for green ammonia production based on renewable hydrogen that could compete with fossil alternatives in scenarios with low electricity prices.

[13] ENTSO-E : European Network of Transmission System Operators https://www.entsoe.eu/

[14] DRI : Direct Reduced Iron (sponge iron); HBI: Hot Briquetted Iron- a compressed form of DRI

6. Changing market regimes, economy and policy

Policy support and subsidies as a driver for investments in the power sector have gained importance in the EU over the past 10 years. Thanks to various volume-based renewable policy instruments such as quota systems, auctions and feed-in tariffs, investment decisions have been decoupled from the price signals given by the spot market (Finon 2013) and the economic focus has gradually shifted away from spot markets to markets for system services such as balancing, capacity and infrastructure (Schleisser-Tappesser 2012). The electricity system is currently in a transitional phase, where the widespread introduction of renewables requires institutional changes to the electricity market regime (Haas et al. 2016, Joskow 2019, Helm and Hepburn 2019). This market transition will require several choices to be made by policy makers to secure competitive electricity prices for industry as part of a new and green industrial policy. Below, we outline four trends that could influence industrial electrification and would need attention from policy makers when developing a green industrial policy for the EU.

(i) The balance between the carbon price and renewable subsidies: The effects that the combined EU climate and energy policies have on electricity prices for industry is determined by the balance between subsidizing renewables that has a downward effect and putting a price on carbon emissions via the EU ETS that has an upward effect. To date, subsidies for renewables have been a stronger driver for decarbonising the power system as the EU ETS has been suffering from lower prices than anticipated. However, this balance between subsidies and carbon prices is likely to change. The EU has a stated ambition to work with and strengthen the existing EU ETS framework, and after a recent reform of the EU ETS, carbon prices have started to increase. At the same time, the need for continued subsidies for renewables is being questioned given the rapidly decreasing cost of renewable electricity generation. A "rebalancing" of climate and energy policies towards a higher carbon price and lower or fewer subsidies would most likely mean higher electricity prices compared to today. However, wholesale electricity prices do not need to become much higher than today, even if they are based on unsubsidised renewables. Long-term cost projections for renewable electricity indicate generation cost levels of 35 to 55 euros/MWh for large-scale deployment (IRENA 2019, Philibert 2019). Lower renewable subsidies

together with a higher carbon price could still promote a transition towards greater use of renewable electricity in the industrial sector by making the fossil-based non-electric energy supply options such as natural gas more expensive compared to electricity. The main fossil fuel option for industrial heating today is natural gas, which could be largely replaced with renewable electricity in the long term. The direct use of natural gas in industry is, in principle, subject to the same level of exemption from energy taxes as the use of electricity. The cost of pipe-delivered natural gas in industry is around 20 to 25 euros/MWh (Eurostat 2019b). An EUA price of, for example, 30 euros/t_CO_2 would mean a carbon cost for the use of natural gas of around 7.4 euros/MWh of gas in industry. However, the energy efficiency of electricity as energy carrier is usually higher than that of gas (EPRI 2018), which makes direct price comparisons less relevant. At what price level industrial electrification would become competitive must be determined for each individual industrial plant.

(ii) Industry engaging directly with renewables producers through Power Purchasing Agreements (PPAs): Industry can also circumvent the fluctuating wholesales market and negotiate PPAs directly with electricity suppliers involved in building the capacity needed for large-scale electrification. For industry, this would mean hedging against the future fluctuating marginal cost and actively taking part in the renewable energy supply. The benefit for power producers would be secure financing with a long-term fixed-price contract. The rapidly growing data-server industry is already active in this field (Koronen et al. 2020). EAF steel and aluminium producers also use PPAs to procure renewable electricity (e-source 2019). This industrial strategy represents a move away from being a passive buyer towards upstream integration and becoming a partner and stakeholder in new power production investments. This is a role that many industries had at the beginning of industrialization in the early to mid-1900s.

(iii) Renumeration for system services: Maintaining balance in this system will come at a cost, and policy-makers will have to allocate cost and create the right market conditions for these services. The fluctuation in future power prices will have to be significant to motivate flexibility measures such as demand response and power-to-gas technology. Short- to medium-term demand response, including both load shifting and load shedding, are already

sold today to various “reserve markets”, and can be scaled up as electricity use in industry increases (Paulus and Borggrefe 2011). Several new flexibility options will also become available in the medium term as existing industrial sites are increasingly electrified (brownfield investments), such as increased use of heat pumps, electric steam generation, and partial synthetic fuel production from CO_2 off-gases (CCU).

Flexibility comes at a cost to industry, and the business case for selling demand-side flexibility is as yet unproven on a large scale. It is still too early to predict whether industrial demand response will have a competitive advantage over batteries or other flexibility options, but for specific EIIs the use of flexibility mechanisms could be a solution for a stable power supply while providing an income to industry. The current market regimes must be adapted and developed to enable greater flexibility. This is currently a priority in the EU Electricity Market Directive (EU COM 2019c). The challenge to industry is to be innovative and to adapt to the changing power system.

(iv) The crucial role of infrastructure development: Securing timely and appropriately sized investments in transmission and distribution capacity will be a key prerequisite for an electrified industry. How the costs are distributed for this expansion of the grid will influence the competitiveness of electricity versus already used energy carriers such as natural gas or energy carriers that are not dependent on dedicated infrastructure and can e.g. use road transport such as solid biomass. From a policy perspective, it could possible to grant industry exemptions from parts of these extra costs, as has been done in Germany, or by way of defining “common interest” sharing the cost for strategic infrastructure among the collective (as a common fee for all infrastructure users). Given the long-term perspective of both grid extension and industrial investments, the ability of the actors to constructively engage in integrated planning is also a key enabler where policy makers have a crucial part to play.

7. Conclusions

During the past 10 years, EU climate and energy policies have added both carbon costs and transitional costs for the support of renewables to be borne by the electricity consumers. The carbon costs, implemented via the EU ETS, have increased the wholesale market price whereas the renewable levies, that are paid off-market, have reduced the wholesale market price. Despite increasing total costs for the electricity system, the EIIs have been able to enjoy relatively stable electricity prices the past 10 years. This is due to the fact that EIIs have been exempted from the renewable levies at the same time as the carbon costs due to EU ETS have remained low. The downward price effect of introducing renewables has been similar or greater than the upward effect of putting a price on carbon emissions. In the cases of Germany and Sweden in 2015, the price reducing effect of the subsidies to renewables was estimated to be about 10 and 4 euros/MWh, respectively. This can be compared with the effect of the price of EUAs, which has increased the price by 4.4 to 4.9 euros/MWh.

It will not be possible to continue current practices as there is increasing pressure to phase out the specific support schemes for renewable electricity production and to rebalance the EU's climate and energy policy towards a higher carbon price via the EU ETS and less, or no, subsidies to renewables. A higher EUA price and less subsidies to renewables will lead to higher prices on the wholesale electricity market for industry but could still promote the electrification of industry as the fossil alternatives (natural gas, oil) would become even more expensive as a result of increasing carbon costs. Renewable electricity has reached a price level where new production would not be substantially higher compared to the average prices the past 10 years.

For supporting a continued electrification of industry in a high carbon price future, the main barrier will not be the electricity price but access to electricity via distribution and transmission grids. Industrial electrification cannot expand relying on current infrastructures and there is a clear need for new infrastructure that will enable both large-scale electrification and sector coupling to gas grids (hydrogen/methane) that will become a key component in a close to 100% renewable electricity system. The EU has recently started to plan more aggressively for the infrastructure needs for an electrified industry but much more needs to be done. From an industry perspective, the allocation of costs, as well as the timing and planning foresight will be key parameters to consider.

The electricity system can be expected to undergo a rapid transition during the next 20 years, and the way in which policy and market regimes are designed will have considerable influence on who bears the cost of this development, and thus on the development of industrial energy demand and integration. A strategy for the long-term electrification of EIIs must take into account the fact that this transition must co-evolve with the changes necessary to achieve a renewable electricity system including the building of new infrastructure and repurposing of e.g. old pipelines. The demand for flexibility and system services will increase as the share of renewable energy sources in the power system increases. Here, industry can play a role through demand response, sector coupling and storage options.

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