COMMON FUTURES

Biomethane for emission abatement by 2040

Using biomethane to reach net-zero emissions in primary steel and dispatchable power

Common Futures | April 2024

Biomethane for emission abatement by 2040

Marginal abatement costs compared to other renewables

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Executive Summary

Biomethane as a renewable energy source can be used to reduce greenhouse gas emissions in various end use sectors. This study aims to provide insights on the abatement costs and potential of biomethane compared to other forms of renewable and low-carbon energy. It shows that **biomethane can play a relevant role as a cost-effective abatement option** irrespective of its sustainable production potential.

This report focuses on the abatement costs of biomethane to produce dispatchable electricity and to provide high temperature heat and carbon-rich feedstock to produce steel, as two relevant examples. Biomethane could perform well in 'sweet spots' in other end use sectors too. Modelling is required to obtain a more definite view on the merits of biomethane in all end use sectors.

Biomethane is produced with **net-zero lifecycle emissions**, if manure is used in the average feedstock mix, and no main crops. Using manure avoids methane emissions which offset the (limited) supply chain emissions from other feedstocks. The greenhouse gas emission performance of biomethane can be enhanced by applying negative emission measures. **Biomethane can provide negative emissions in in three ways**: (1) carbon storage in the soil when growing biomass, (2) pre-combustion carbon capture in the production of biomethane and (3) post-combustion carbon capture when using it.

Production costs of biomethane could be €70 per MWh on average, noting that production in large installations is significantly cheaper than in smaller ones. This cost level equals a renewable hydrogen cost of just over €2 per kilogramme.

The marginal abatement cost curves presented as example case studies in this report show that biomethane is a cost-efficient abatement option in the production of dispatchable electricity and in primary steel production. The abatement potential of biomethane in both assessed sectors is capped by the supply potential that can be made available for consumption in these sectors.

In the electricity system, electricity from biomethane is the **most cost-effective option to balance the electricity system in particular during 'windless winter weeks'**[1], making use of inexpensive storage in existing gas storages. In primary steel production, biomethane can be used in the DRI process, thereby replacing existing steel production that uses cokes coal. Most steel abatement options end up with remaining emissions. **Biomethane combined with CCS is not only the most cost-effective option to achieve net zero emissions steel production, but beyond that it achieves climate positive steel**.

[1] Kees van der Leun, Windless Winter weeks (2016), see: Windless winter weeks | PPT (slideshare.net).

Table of Contents

1. Introduction **5**

1.1. How to read this report *5*

1.2. Study scope excludes energy infrastructure *6*

2. Sustainable biomethane by 2040 .... **7**

2.1. Sustainable feedstock mix leads to net zero emissions biomethane *7*

2.2. Net-zero emissions biomethane can be produced for €70 per MWh *9*

2.3. Ability to generate negative emissions beyond the 'base case' *9*

2.4. Allocating biomethane over end use sectors *11*

3. Biomethane as an abatement option in dispatchable electricity generation **12**

3.1. Baseload and dispatchable electricity to balance the system *13*

3.2. Biomethane as lowest-cost abatement option for dispatchable power from gas-fired power plants . *15*

4. Biomethane as an abatement option for primary steel production **18**

4.1. Biomethane is the lowest-cost abatement option for primary steel *18*

4.2. The value of negative emissions and overview of total costs of each abatement option *20*

5. Biomethane for carbon rich feedstock **23**

6. Annexes: creation of the MAC curves **24**

6.1. Annex I - Dispatchable electricity *24*

6.2. Annex II – Steel production *25*

6.3. Annex III – Energy costs *27*

1. Introduction

In early 2024, the European Commission published a Communication on the 2040 EU climate target, accompanied by an Impact Assessment. This will inform a draft law setting the 2040 target.

This report aims to provide insights on the role biomethane could play to reduce (abate) greenhouse gas emissions in the EU to net-zero by 2040, and its relative abatement costs and potential compared to other abatement measures. This is done by creating marginal abatement cost curves in dispatchable electricity production and in providing thermal energy and feedstock in primary steel production as case studies to analyse the relative value of biomethane compared to other abatement options.

Biomethane can play a role as an abatement option in many end use sectors. This study focuses on primary steel and dispatchable power. The role for biomethane in primary steel production was chosen as an example because it is not yet a well-known abatement option and therefore possibly does not play a significant role in scenarios for achieving net-zero emissions in primary steel. The use of biomethane in the power sector was selected as an example because of new insights in its production costs and because gas-fired power plants will be an essential source of dispatchable, net-zero emissions electricity according to the TYNDP 2022 scenarios.

What is a marginal abatement cost curve?
A marginal abatement cost curve, or MAC curve, shows the costs and emission reduction potential of greenhouse gas mitigation or abatement measures relative to a fossil comparator. The vertical axis shows the costs per tonne of CO_2 equivalent of each abatement option. Options that are cheaper to implement compared to the fossil fuel comparator per unit of energy lead to negative abatement costs while measures that are more expensive compared to the fossil fuel comparator have positive abatement costs. The horizontal axis of the curve shows the total contribution of each abatement option to reduce emissions at the given abatement cost. The measures, represented by blocks in the curve, are ranked from lowest (negative) to highest abatement costs. It is assumed that the ones with lowest cost will be applied first, so the blocks to the left of the desired total abatement (on the horizontal axis) are the ones that will be applied.

1.1. How to read this report

This report uses best available insights on energy and technology costs from existing studies and puts them together to create MAC curves.
Chapter 2 describes the biomethane feedstock mix and lifecycle emissions of biomethane as well as production costs, and explores options to enhance the emission performance of 'base case' biomethane by its ability to generate negative emissions.
Chapter 3 describes the value of biomethane as an emissions abatement option in creating a net zero emissions EU electricity system by 2040. Biomethane-based electricity is compared to other renewable options to produce renewable baseload and dispatchable electricity. Cost assumptions for renewable electricity production are taken from published TYNDP 2024 scenario data, where needed TYNDP 2022 data and data taken from the open source Energy Transition Model.

Chapter 4 provides a simplified marginal abatement cost curve for options to provide high temperature heat and carbon-rich feedstock to produce green steel. Information of abatement options and costs other than biomethane are mostly taken from a study performed by the Netherlands Environmental Assessment Agency (PBL). This high-level analysis could be improved by using data and insights from steel producers.
Finally, **Chaper 5** briefly describes how biomethane can provide carbon-rich feedstock to industry.

1.2. Study scope excludes energy infrastructure

An important limitation of the input provided in this report is that energy infrastructure is not considered. To achieve a net zero emissions energy system, with a significantly increased role for electricity, large investment costs are needed to expand electricity transport and distribution infrastructure. In the Netherlands, for example, the electricity and gas TSO and DSOs expect to invest €64 billion in electricity infrastructure up to 2030, while maintaining existing gas infrastructure will cost €6 billion[2] and building the first 1200 km of hydrogen backbone largely by repurposing gas pipelines will cost up to €1.5 billion.

The smart use of biomethane in various end use sectors has the potential to significantly lower the cost of expanding electricity infrastructure. For example, the use of small quantities of biomethane (around 300 m^3 per home) in older homes with an existing gas connection in a hybrid heat pump, can significantly lower the electricity demand peaks compared to an electric heat pump, which is especially relevant during windless winter weeks.[1] Such solutions lead to significant savings in electricity grid expansion and required dispatchable power generation capacity.[3]

While transmission and distribution infrastructure is excluded, the study does include cost estimates for energy storage needed for dispatchable electricity production, including the costs for biomethane storage in existing gas storages, underground hydrogen storage and battery storage.

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[2] Netbeheer Nederland, De financiële impact van de energietransitie voor netbeheerders. Geactualiseerde prognose 2023 (in Dutch), see here: De energietransitie en de financiële impact voor netbeheerders (netbeheernederland.nl).
[3] Gas for Climate, the optimal role for gas in a net-zero emissions energy system (2019)

2. Sustainable biomethane by 2040

This chapter describes the sustainable feedstock mix and associated emission savings in the EU by 2040. It shows that biomethane can be produced with net zero lifecycle emissions, taking into account avoided methane emissions. Its emission performance can be enhanced through negative emissions. Biomethane can generate negative emissions in three ways: through soil organic carbon accumulation, by capturing and storing biogenic CO_2 from the production process and by applying post-combustion CCS when using biomethane in industry.

2.1. Sustainable feedstock mix leads to net zero emissions biomethane

Total abatement potential depends on biomethane's sustainable supply potential
Biomethane can be produced through anaerobic digestion or gasification. The sustainable supply potentials for both pathways depends on the availability of sustainable biomass feedstock and determines. This report assumes that by 2030 more than 35 bcm sustainable biomethane will be produced and that further growth will take place post 2030. How much further growth and how large therefore biomethane's total abatement potential would be, falls outside the scope of this report.

Marginal abatement costs depend on biomethane's production costs and emissions saving
When estimating the abatement cost of biomethane, it is necessary to estimate the production cost and greenhouse gas emission savings per unit of biomethane. The latter depends on the overall feedstock mix and the associated supply chain emissions of specific production pathways.
By 2030, biomethane production will be largely based on anaerobic digestion, while first of a kind gasification-based biomethane can be could become operational around 2030. For the post-2030 period, it can be assumed that gasification-based biomethane can gradually start to play a larger role, although it can be assumed that during 2030-2040 anaerobic-digestion based biomethane will still scale faster than gasification-based production. For the purpose of this report it is assumed that anaerobic digestion based biomethane can by 2040 achieve 75% total production whereas gasification can cover 25% of total production.

Assumed feedstock mix
The feedstock mix of gasification-based biomethane consists of wood waste, forestry residues, municipal solid waste, landscaping wood and prunings. As the harvesting, collection and processing of these feedstocks have similar supply chain emissions there is no need in this report to estimate a specific feedstock mix. Greenhouse gas emissions from the cultivation, harvesting or collection and processing of feedstocks used in anaerobic digestion differ significantly. Therefore, for the purpose of this report, an example feedstock mix for 2040 is assumed, pictured in the diagram below (Figure 1).

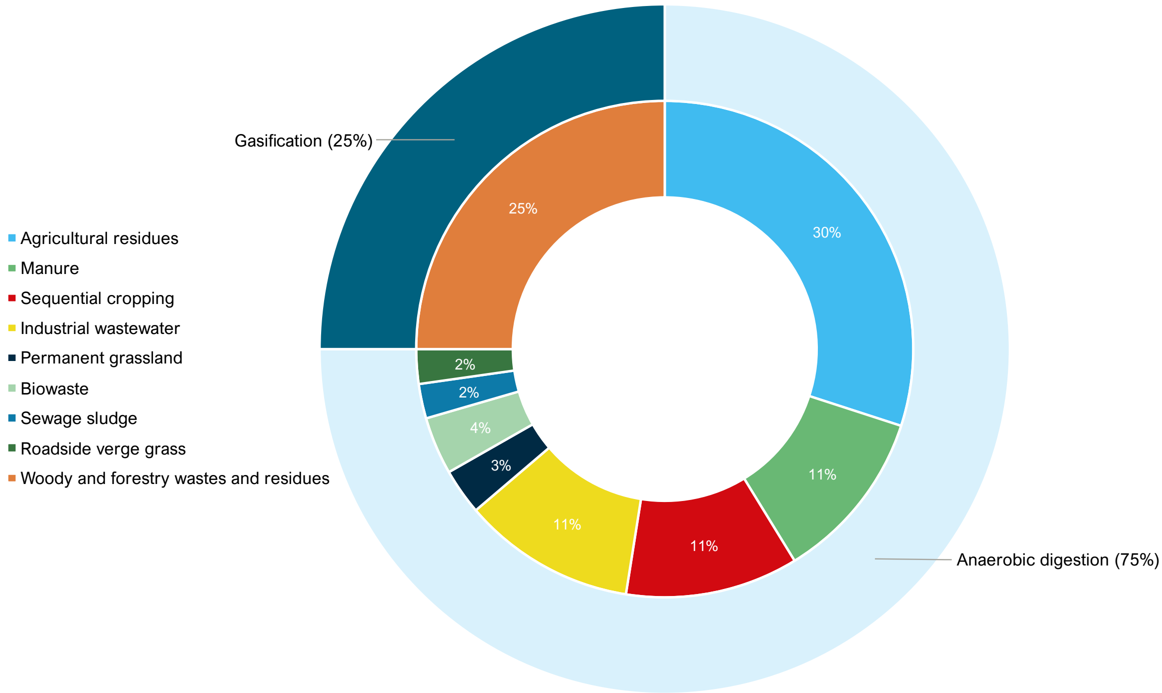

Figure 1. Example feedstock mix for 2040 used in this analysis.

Net-zero greenhouse gas emissions for biomethane as 'base case'

Annex V, part C of the EU RED describes the supply chain emissions of wet manure (8.9 gCO_{2eq}/MJ), maize[4] and biowaste (10.1 gCO_{2eq}/MJ) feedstocks for biomethane production by anaerobic-digestion. In addition, Annex V provides a credit of -111.9 gCO_{2eq}/MJ for abated methane emissions from the use of manure. For production of sequential crops this report assumes cultivation emissions of 50% of those of maize, and the same processing and upgrading emissions as when maize is used,[4] resulting in assumed supply chain emissions of 17.6 gCO_{2eq}/MJ. For production from agricultural residues, industrial wastewater, permanent grassland, sewage sludge and road side verge grass, the same emission factor as when using biowaste is assumed (10.1 gCO_{2eq}/MJ). For sewage sludge this is likely an overestimation since using this feedstock can lead to reduced methane emissions at the sewage treatment facility. For the example feedstock mix for anaerobic digestion presented in Figure 1, this results in average supply chain emission of -5.74 gCO_{2eq}/MJ.[5]

Emissions from gasification production pathways are assumed 17.5 grams of CO_2-equivalent per MJ of biomethane, based on a study by CE Delft[6] that analyses emissions of wood-based gasification to biomethane. It is assumed that emissions for this pathway are similar to others, noting that using municipal solid waste could lead to avoided methane emissions that are not yet taken into account.

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[4] The EU RED typical value greenhouse gas emissions for biomethane production from maize (whole plant) are 17.6 gCO_{2eq}/MJ for cultivation, 4.3 gCO_{2eq}/MJ for processing, 4.5 gCO_{2eq}/MJ for upgrading, and 3.3 gCO_{2eq}/MJ for compression at filling station.

[5] The example 2040 feedstock mix used in this analysis uses a conservative assumption for the contribution of manure, being 15% of the feedstock mix for anaerobic digestion. Increasing this contribution to 25%, with a lower share of other feedstocks, would decrease the supply chain emissions of biomethane from AD plants to -17,2 gCO_{2eq}/MJ.

[6] CE Delft, CO_2 balansen groen gas ketens. Vergisting en vergassing (2019), p. 35-37. Full study in Dutch and English summary available here: LINK.

The assumed 2040 feedstock mix results in average supply chain emissions per unit of biomethane of just below zero grams of CO_2-equivalent per MJ. This does not yet take into account negative emissions.

2.2. Net-zero emissions biomethane can be produced for €70 per MWh

Biomethane production costs can vary significantly depending on the size of the installation and the country of production. Recently, Task Force 4 of the Biomethane Industrial Partnership has performed a first-of-a-kind data exercise to collect real cost data from the biomethane industry based on an anonymous process. This has led to a production cost estimate (excluding producer margin) of **€54/MWh** for biomethane produced in **large-scale installations** and **€84/MWh** for biomethane produced in **medium-sized installations** with a capacity of about 13 MW, producing 1200 cubic metres of biomethane per hour.[7] These are 2021 cost levels. Since then production costs have gone up yet further innovation may lead to future cost decreases. This report considers biomethane as a 2040 abatement option at assumes average production cost level of **€70/MWh,** the average 2021 cost of production of a large and a medium scale installation, and assumes that this cost level will be relevant for 2040.

No reliable cost data are available for gasification-based biomethane because this technology has not yet been implemented for biomethane production at commercial scale. Based on studies[8], this report assumes a **2040 a cost of €70/MWh for gasification-based biomethane could be feasible**. This is equal to green hydrogen at just over €2 per kilogramme.

2.3. Ability to generate negative emissions beyond the 'base case'

Beyond the emission performance of biomethane as a renewable gas, as described in Section 2.1, biomethane also has ability to generate negative emissions in three ways. Firstly, applying sustainable practices during feedstock production can result in soil organic carbon accumulation which creates a below-ground carbon sink. Secondly, in the production of biomethane a pure stream of biogenic CO_2, becomes available that can be captured and sequestered (pre-combustion CCS), and finally it is possible to apply CCS when using biomethane in industry or electricity generation (post-combustion CCS). These three negative emission options improve biomethane's emissions performance compared to the 'base case'.

Soil organic carbon accumulation takes place when feedstock is cultivated while keeping the soil covered and applying low tillage practices while leaving some above and below-ground biomass on the field and preventing erosion. The EU RED recognises the ability to accumulate below-ground carbon in degraded land that was not in agricultural use in 2008 and was severely degraded with an emission bonus of 29 gram gCO_{2eq} per MJ biomethane. This way to generate negative emissions is relevant for cultivation of sequential crops. The European Commission stated in its Impact Assessment

[7] Large installations have been defined as 13MW installations that produce 1200 cubic metres of biomethane per hour or 100 GWh. Smaller installations are 5MW installations that produce 500 cubic metres of biomethane per hour or 42 GWh. Actual costs for 2021 were collected, noting that during 2022 and 2023 production costs have been volatile and increased.
[8] An analysis is provided in Gas for Climate, the optimal role for gas in a net-zero emissions energy system (2019).

to the soil quality directive that 37% of EU agricultural soils are degraded.[9] It is unclear to what extent these soils were not in production in 2008 and therefore what contribution of SOC accumulation can be recognised based on the EU RED. If it would be assumed that 37% of sequential cropping takes place on degraded land and would receive the SOC accumulation bonus of 29 gram gCO_{2eq}/MJ, this could in principle generate 0,003 tCO_2/MWh biomethane over the average 2040 sustainable production potential, or 0.3 kilogramme per m^3 of biomethane. It should be noted that this option for negative emissions is relevant only if agricultural biomass (residues, sequential cropping) is used as feedstock.

Pre-combustion CCS uses biogenic CO_2 captured at the biomethane plant. Biogas has a CO_2-content of around 40% that can be captured in a concentrated form without much pollutants. This CO_2 would typically be transported to a CO_2 pipeline or a storage location in liquid form before being stored below ground. This could generate negative emissions of about 0.12 tCO_2/MWh of biomethane, or about 1.3 kilogramme of CO_2 per m^3 of biomethane. Gasification-based biomethane can also generate negative emissions in a similar order of magnitude. However, biomethane production installations will be located throughout the EU and will often be located too far away from storage locations or CO_2 transport infrastructure. Therefore it is assumed that only 25% of biomethane production in 2040 can be combined with pre-combustion CCS.

In addition to soil carbon accumulation and pre-combustion CCS, biomethane can generate negative emissions by applying **post-combustion CCS** when using biomethane for industrial heat or electricity production. This can be relevant in e.g. steel production where CCS is already explored as an abatement option and around 70% of emissions could be captured and stored.

Cost and emission abatement potential of biomethane production with negative emissions
The previous section describes three ways in which biomethane can generate negative emissions. This report assumes that soil carbon accumulation does not come at an additional cost at the farm. Pre-combustion CCS requires costs for capturing/liquefaction, transport and storage. Taking the higher end of cost estimates published by Eurelectric,[10] capture costs can be €23.5/tCO_2, plus €8/tCO_2 for pipeline transport to storage location and €23.5/tCO_2 for storage. An additional €10/tCO_2 for truck transport to the CO_2 pipeline has also been included. This leads to a cost of **€65/tCO_2 for pre-combustion CCS by 2040**. The costs of post-combustion CCS (which takes place at the end-user rather than at the biomethane plant) are estimated to be **€112/ tCO_2**.[19]

To analyse the potential contribution of biomethane to generate negative emissions, this report looks into the impact of SOC accumulation or implementing pre-combustion CCS on the **cost and emission abatement of biomethane production from an individual biomethane plant**. The findings, presented in **Fout! Verwijzingsbron niet gevonden.**, highlight that SOC accumulation and pre-combustion CCS can generate significant negative emissions in a cost-efficient manner.

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[9] SWD(2023) 417 final part 3/5. Impact Assessment report annexes accompanying the Soil Monitoring Law proposal, p. 206-207. At the same time, SWD(2023) 417 final part 4/5 states on p. 691 that 53% of EU agricultural land shows loss of soil carbon.
[10] Eurelectric (2023). Decarbonisation Speedways. p.73.

2.4. Allocating biomethane over end use sectors

This report does not propose an allocation of biomethane over end use sectors. Yet for the purpose of creating MAC curves it is necessary to determine the maximum abatement potential of biomethane per end-use for which a curve is created. Therefore, this report assumes that out of the total sustainable biomethane potential by 2040, 20 bcm of biomethane will be available for dispatchable power production by 2040 and 15 bcm for primary steel production. While it is feasible to analyse production potentials, it is hard to estimate actual production by 2040 and its allocation over sectors. The allocations used in this report therefore are illustrative only and the quantity of biomethane used in each demand sector does not influence the relative ranking of biomethane in MAC-curves in terms of abatement costs per tonne of CO_2.

3. Biomethane as an abatement option in dispatchable electricity generation

This chapter describes the value of biomethane to contribute to a net zero electricity system by 2040 in the most cost effective way. Biomethane can be cost-efficient in the production of dispatchable electricity to balance the system, in particular during 'windless winter weeks'. Biomethane is a cost-competitive option to generate zero-emission dispatchable electricity.

Renewable electricity from wind and solar-PV will be the dominant source of electricity production in the net-zero emissions electricity system by 2040. In addition, dispatchable and baseload power sources will be needed to balance the system. The TYNDP 2022 scenarios estimate a total electricity supply of 4,600-5,300 TWh of which 1,258-1,360 TWh produced from dispatchable and baseload supply from hydropower, nuclear power, and gas-fired power plants.[11] Marginal abatement cost curves for dispatchable electricity generation in both TYNDP scenarios are shown in Figure 3 and Figure 4. In creating these, TYNDP data are used, complemented with own data on biomethane. They show that existing hydropower and nuclear power plants are the most cost-effective options, followed by biomethane. Biomethane is more cost-efficient than renewable hydrogen, even without taking into account biomethane abatement costs reductions from applying options for negative emissions.[12] This because hydrogen-fired power plants (CCGTs) have slightly higher capital and operational costs and relatively high costs for hydrogen storage. The role of biomethane is limited by its supply potential, and its demand in other sectors. As a result hydrogen is likely to also play a role in dispatchable electricity production. The following sections will explain this in more detail.

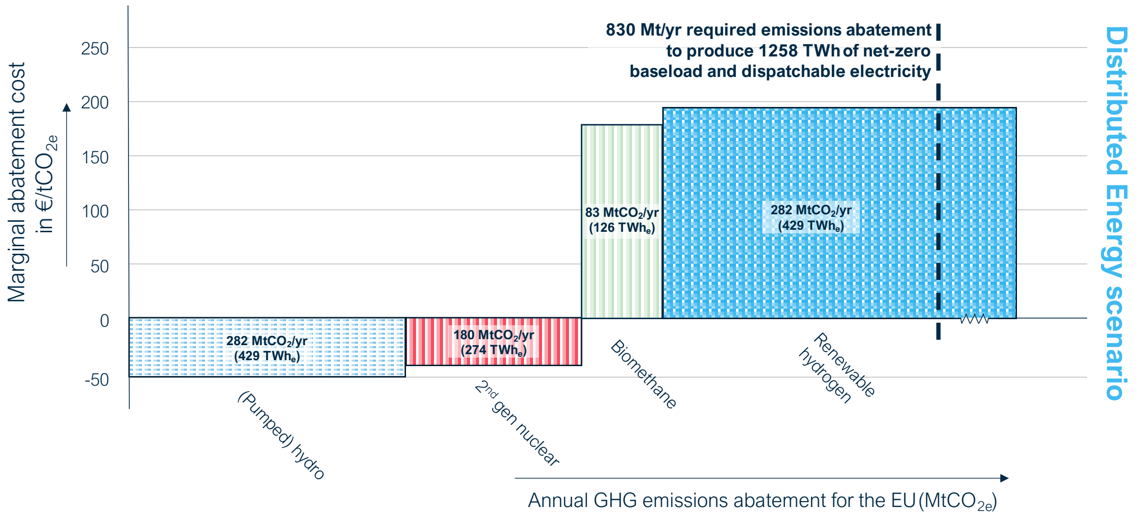

Figure 2. MACC for dispatchable and baseload power, largely based on the values in the TYNDP 2022 Distributed Energy scenario, showing biomethane to be a cost-competitive abatement option.

[11] Based on Figure 25 of the TYNDP 2022, looking at the 2040 power mix in the Global Ambition and Distributed Energy scenarios

[12] Even with the assumption that hydrogen production costs (both CAPEX and OPEX) will decrease significantly by 2040, based on TYNDP 2024 assumptions, resulting in renewable hydrogen production cost of ~€2 /kg, down from about €6-8/kg today.

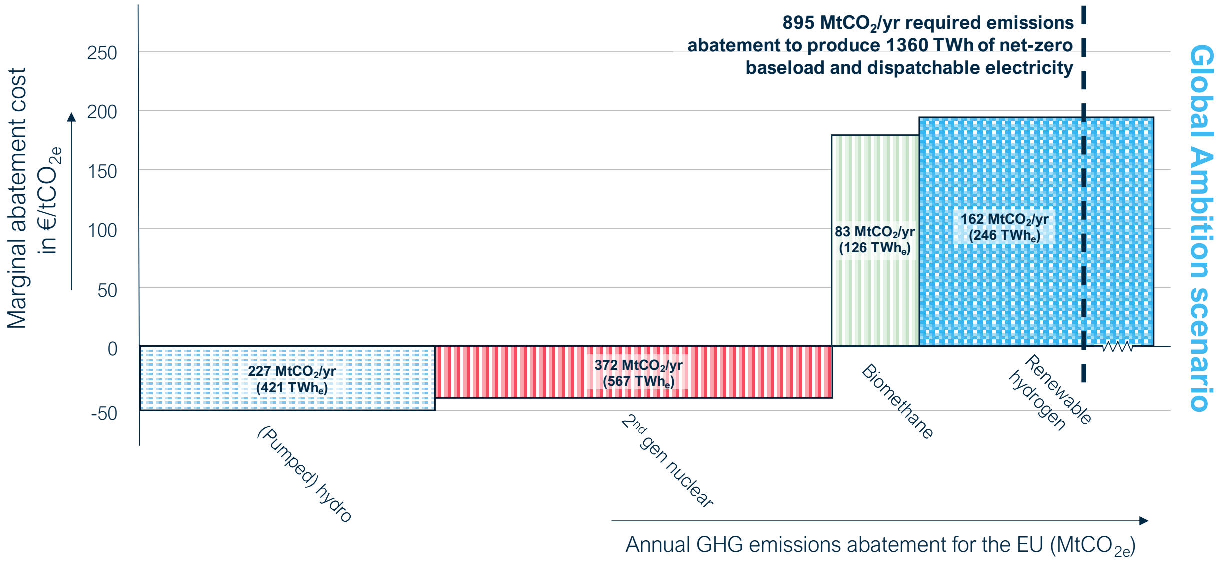

Figure 3. MACC for dispatchable and baseload power, largely based on the values in the TYNDP 2022 Global Ambition scenario, showing biomethane to be a cost-competitive abatement option.

3.1. Baseload and dispatchable electricity to balance the system

Dispatchable and baseload power sources cover up to 30% of the of electricity demand in 2040 in the TYNDP scenarios

Onshore wind, offshore wind and solar PV will play a dominant role in the net zero emissions EU power mix in 2040. Their low OPEX and CAPEX make solar PV and wind power the cheapest zero-emission power generation technologies, economically superior when the electricity produced can be used directly. These intermittent sources, however, need to be complemented by energy storage and dispatchable and baseload sources to match demand and supply during the year, especially during periods with low availability of sunlight or wind and periods with peaks in demand. In the TYNDP 2022 scenarios Distributed Energy (DE) and Global Ambition (GA), baseload and dispatchable sources produce 1,258-1,360 TWh of electricity in 2040 respectively, accounting for 23-30% of the total electricity supply. Dispatchable and baseload electricity sources included in the TYNDP scenarios are hydropower, nuclear, and gas-fired powerplants.

Seasonal dispatchable deployment of solar and wind with batteries is expensive

The surplus from wind and solar can be used in dispatchable electricity using batteries. However, the deployment of batteries for dispatchable purposes other than day and night balancing is very expensive. Satisfying the electricity demand during an extended period of low solar and wind power would require large amounts of battery capacity, that are deployed to a limited extent during the rest of the year. This results in very low annual cycles for these batteries, increasing the additional cost of dispatchable electricity with ~€1,600/MWh_e. As a result, the marginal abatement cost for deployment of solar and wind with batteries becomes prohibitively high (see Figure 5).

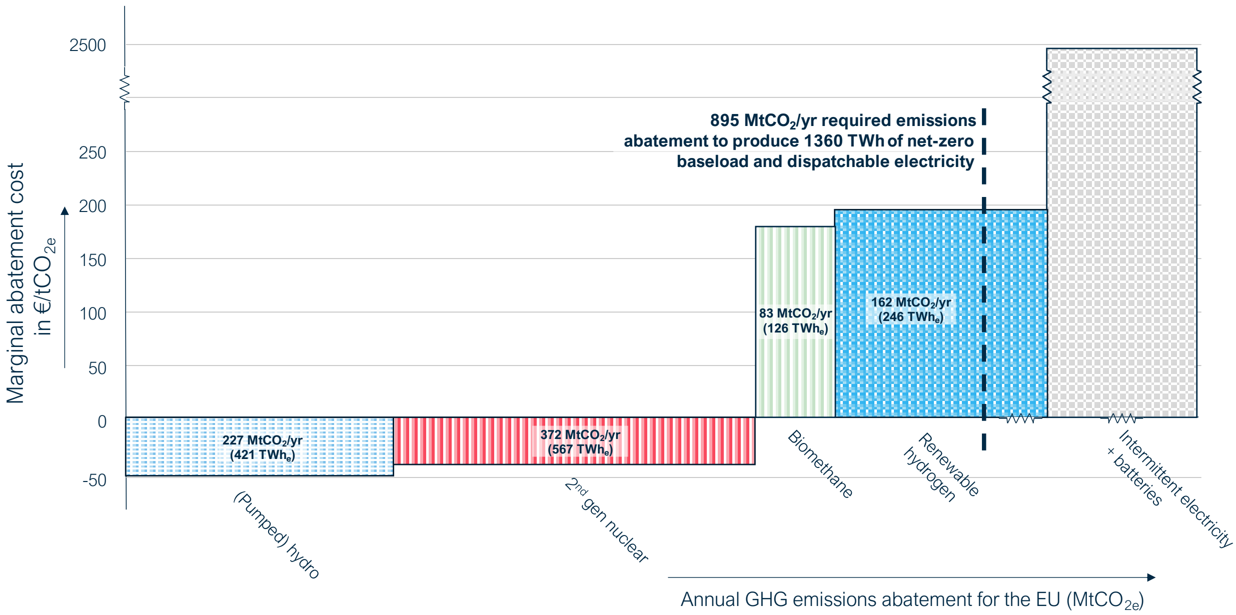

Figure 4. MACC for dispatchable power (GA scenario), showing that intermittent electricity with batteries is a very expensive abatement option for dispatchable power.

Hydro and nuclear are cost-efficient sources of power during windless winter weeks, but limited in their capacity and flexibility

Solar and wind are economically followed by hydropower: its marginal costs are practically zero. As a result, hydropower plants will likely run at full capacity in hours with little wind and solar. Hydropower is an important source of electricity in the EU today, representing around 13% of the power mix in 2022 with a total installed capacity of 151 GW (of which 83 GW dispatchable reservoir hydro), but the installed hydropower capacity is not expected to increase significantly until 2040.[13] The TYNDP 2022 DE and GA scenarios assume the installed hydro and pumped storage capacity in 2040 to be 173 GW, producing 429 TWh$_e$ and 421 TWh$_e$ respectively.

A special type of hydropower is pumped hydro. The pumped hydro reservoir can be filled in hours with cheap electricity and used to produce electricity in hours with too little wind, solar, nuclear and regular hydropower. Its current total installed capacity is ~45 GW, and only limited growth can be expected.

Nuclear power has higher marginal costs than wind and solar, but significantly lower than gas-fired power plants. Nuclear power is currently an important source of electricity, covering around 22% of the total supply in 2022 with 100 GW of installed capacity. Existing nuclear power plants are somewhat flexible, yet to a lesser extent than CCGTs, both in capacity and ramp-up speed. As a result, nuclear power plants will likely run many hours, including the hours with little wind and solar. The installed capacity is not expected to grow until 2040: new construction is limited because of the high investments, the uncertain business case and relatively long construction times. The TYNDP 2022 DE and GA scenarios assume the installed nuclear capacity in 2040 to be 45 GW and 97 GW respectively, producing 274 TWh$_e$ and 567 TWh$_e$. The DE scenario assumes that a significant part of existing capacity will be shut down before 2040.

[13] JRC (2022). Clean Energy Technology Observatory: Hydropower and Pumped Hydropower Storage in the European Union – 2022 Status Report on Technology Development, Trends, Value Chains and Markets. See: LINK

Gas-fired power plants are needed to fill the gap

The installed capacity of nuclear and (pumped) hydropower is limited and cannot cover the full remaining electricity demand in periods with little solar and wind. Scenario studies confirm this: the capacity gap the supply of these sources and the demand for electricity can be as high as 400 GW, assuming limited growth in nuclear and hydropower capacity.[14] In addition, the sources are limited in their dispatchability. Only 83 GW out of the 150 GW of installed hydropower capacity can adjust its production according to needs. Nuclear plants can only scale down to a maximum of 40-60% of their total capacity, and their ramp-up rate is four times slower than that of CCGTs. As a result, gas-fired power plants are needed to fill the gap. In the TYNDP DE and GA scenarios, gas-fired power plants supply 555 TWh_e and 372 TWh_e of electricity respectively.

For gas-fired power plants, there are three zero/low-emission options: 1) natural gas with CCS, 2) (green or blue) hydrogen, and 3) biomethane. Since the gas-fired power plants will only operate ~1,500 hours annually by 2040,[15] CCS is prohibitively expensive because of its high capital costs, which leaves hydrogen and biomethane as the emission abatement options. The TYNDP 2022 scenarios still had 200-300 TWh of unabated natural gas-fired power in 2040, but the current EU-ETS trajectory makes that unlikely.

3.2. Biomethane as lowest-cost abatement option for dispatchable power from gas-fired power plants

Our analysis shows that biomethane-based electricity is a relevant and cost-competitive abatement option in providing power on a dispatchable basis. From the marginal abatement costs, visualised in

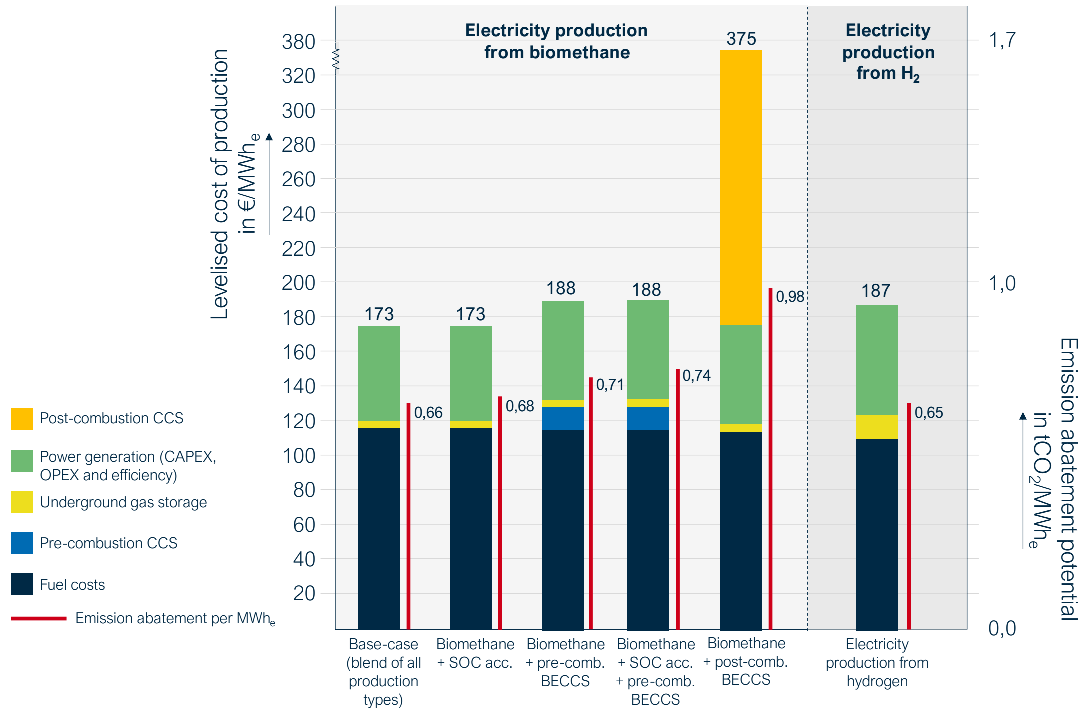

Figure 5: Levelised cost of production and emission abatement potential of (electricity from) biomethane and hydrogen.

[14] TYNDP (2022). Scenario report data figures (excel). Sheet 29a. See: LINK

[15] TYNDP (2022). Scenario report. Figure 27. See: LINK, page 39.

Figure 6, it can be concluded that 'base case' biomethane[16] (~€175/tCO_2) is a more cost-effective abatement option compared to hydrogen (~€195/tCO_2). This is mainly a result of the slightly higher CAPEX and OPEX for hydrogen-fired CCGTs, and the relatively high cost of hydrogen storage. In addition, the emission abatement potential per MWh_e is slightly higher for biomethane, especially when accounting for its potential to generate negative emissions (see Figure 7).

Options to generate negative emissions increase the cost-effectiveness of biomethane as an abatement option for dispatchable electricity

When combining biomethane production with options to generate negative emissions, notably soil organic carbon (SOC) accumulation and pre-combustion carbon capture and storage using biogenic CO_2, biomethane becomes an even more attractive abatement option, with a combined abatement cost of ~€160/tCO_2 (see Figure 7). As indicated in the introduction, this comparison excludes the system costs related to infrastructure expansion (electricity) or infrastructure conversion (hydrogen), which would provide an even more favourable picture for biomethane.

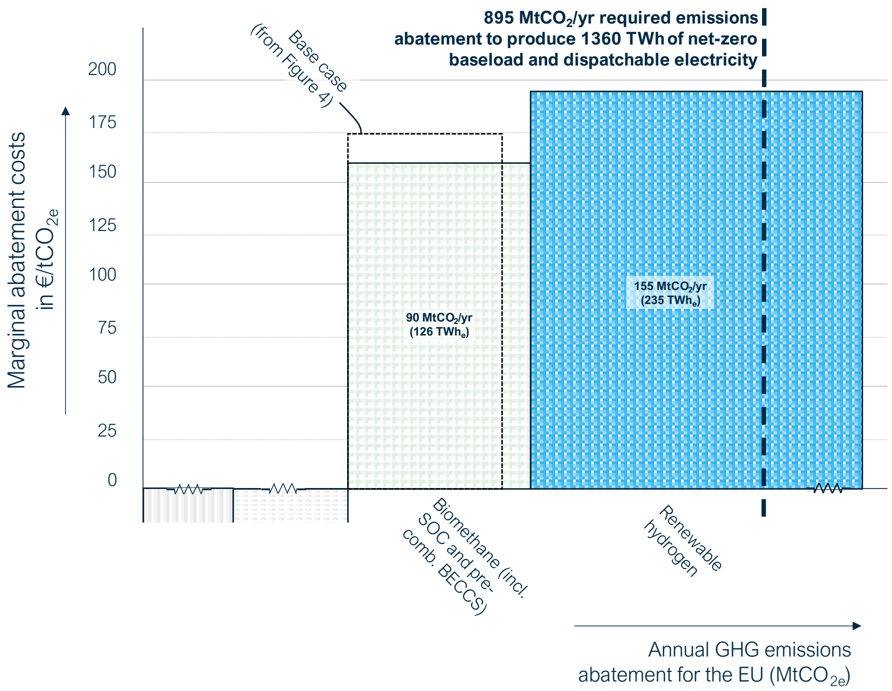

Figure 6: Zoom-in of the MACC for dispatchable and baseload electricity to show in more detail the comparison between electricity from biomethane (with negative emissions) and hydrogen.

Hydrogen is likely to also play a role in dispatchable electricity production

The role of biomethane as an abatement option in dispatchable power is limited by its supply potential, and its demand in other high value applications. Meeting the 200-300 TWh_e of unabated natural-gas fired power in 2040 in TYNDP 2022, would require 333-500 TWh of biomethane. To consider the system value of biomethane as an abatement option in residential heating and industry, the analysis assumes the biomethane available for electricity production is limited to a maximum of 20 bcm equalling 210 TWh_{th} or 126 TWh_e. This makes it likely that there is also a role for hydrogen in

[16] Base case biomethane is biomethane without negative emission options being applied. This biomethane is a blend of biomethane produced by large-scale anaerobic digestion, small-scale anaerobic digestion and gasification.

dispatchable electricity production alongside biomethane. The role of biomethane in dispatchable power production depends on its sustainable production potential and of the energy system value of using biomethane in other end use sectors. If less than 20 bcm of biomethane is available for electricity production, the role of hydrogen in dispatchable power increases.

4. Biomethane as an abatement option for primary steel production

This chapter describes the marginal cost and potential of different abatement options for primary steel production. It shows that biomethane is a cost-effective option to achieve net zero emissions primary steel production by 2040. When combined with CCS it can even achieve negative emissions.

4.1. Biomethane is the lowest-cost abatement option for primary steel

By 2040, primary steel production in the EU is expected to be around 68 million tonnes or 50% of total EU steel making, down from 57% currently. The MAC curve in Figure 8 below compares various ways to produce this quantity of steel with net zero greenhouse gas emissions, each with their costs compared to the cost of the fossil comparator. The fossil comparator is existing primary steel production using coal in a Blast Furnace and Basic Oxygen Furnace (BF/BOF). This fossil comparator produces hot rolled coil steel at a cost of €419/t steel (2017 euros), generating 1.92 tCO_2/t steel (see Annex II for further details).

All viable emission abatement options involve a technology shift from blast furnace to direct reduction of iron ore (DRI). This technology no longer uses coal but either natural gas, biomethane or hydrogen. As can be seen below, using biomethane has the lowest overall abatement costs. This is especially the case if valuable negative emissions are created by combining biomethane with CCS. Importantly, even without CCS, biomethane use in steel production comes with the lowest marginal cost as it provides a much needed carbon source without fossil fuel emissions, unlike the hydrogen and natural gas blending abatement route. As a result of natural gas use here there are some remaining emissions that must be compensated for at the cost of CO_2 emissions in 2040, at an expected high carbon price.

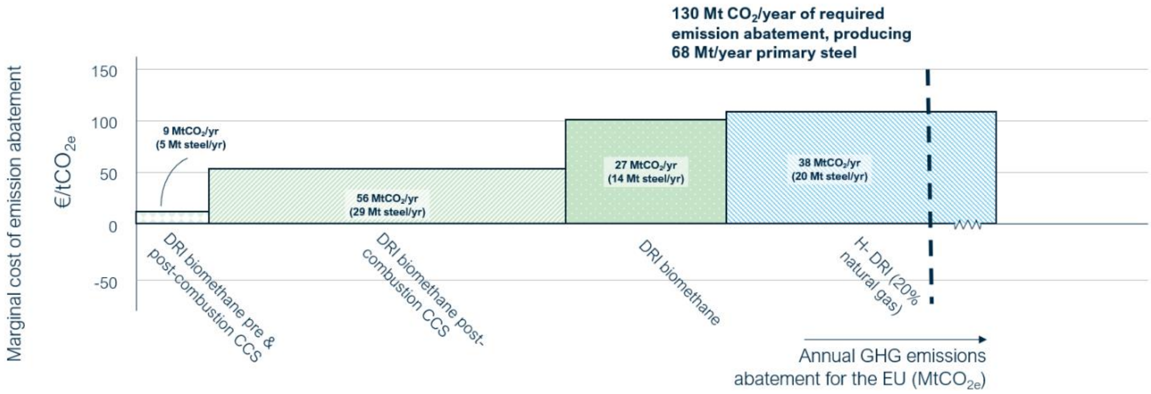

Figure 7. Marginal cost abatement curve for primary steel production in the EU in 2040.

The extent to which biomethane can be used depends on the availability of biomethane to the steel sector. If it is assumed that by 2040 15 bcm of biomethane is available to steel producers, this would produce 48 Mt of green steel. Other abatement options, including the use of hydrogen, will be required to produce an additional quantity of 20 Mt of steel annually to meet the estimated 2040 market size. Limitations on the availability of biomethane, and also the availability of CCS to biomethane and steel producers can have a notable impact on this curve.

The role of pre- and post-combustion CCS in steel production is capped

Using biomethane in DRI, combined with both pre- and post-combustion CCS as fuel source gives the lowest marginal abatement cost, with an abatement cost of €13/tCO_{2e} compared to the fossil fuel comparator. This very low cost results from the large negative emissions generated in this abatement route and the high value of negative emissions in 2040, outweighing any cost increases from CCS or fuel costs. However, the negative emissions of biomethane from pre-combustion CCS are only assumed to be allocated to the steel sector when its production is owned and operated by the steel producer. Only then it makes sense that the negative emissions from pre-combustion CCS can be allocated to the steel sector without having to pay the CO_2 market price for it by 2040. For the purpose of creating this MAC curve we used an example quantity of 10% own fuel production by steel companies, just to show the emission benefit of this option. Consequently, a maximum of 10% of the assumed 15 bcm of biomethane available for green steel is assumed to be combined with pre-combustion CCS, producing 5 Mt steel a year.

Biomethane use in the DRI shaft with post-combustion CCS is the next lowest marginal abatement cost, with an abatement cost of € 54/tCO_{2e}. This low abatement cost is again linked to the value of negative emissions generated by BECCS. Despite this low cost it is assumed it will not be possible to apply CCS in every primary steel plant across to the EU. Therefore, this report assumes 50% of primary steel production can be coupled with CCS, which limits the potential of biomethane in DRI with post-combustion CCS to 29 Mt of steel production.

Production using natural gas in DRI with CCS has the next lowest marginal abatement cost. However, because of the assumption on limited availability of post-combustion CCS, this abatement option is not displayed in the marginal abatement cost curve.

Biomethane use in DRI gives the lowest abatement cost even without CCS

Given the above assumption that half of annual primary steel production must come without post-combustion CCS, DRI shafts without CCS are required. For this the lowest abatement option still involves biomethane. This is the result of the emission reduction potential of this abatement route and the slightly lower fuel costs compared to other abatement routes without CCS. This shows the value of biomethane as an abatement option in the steel industry as biomethane is the least-cost abatement option both when combined with CCS and without CCS. It should be noted here that the cost advantage over hydrogen routes is diminished without CCS, suggesting potential for both solutions under different assumptions on fuel costs.

However, hydrogen (with some natural gas) will also play a role

Biomethane can play a significant role in producing net-zero emissions primary steel but will not be available in limitless quantities. Therefore, it is likely that hydrogen will be needed too. DRI using a mix of 80% hydrogen and 20% natural gas has the lowest marginal abatement cost when the availability of biomethane is exhausted.

Table 1 presents the marginal abatement costs and absolute emission reduction of each abatement of abatement options presented in the MAC curve and shows the from each option used construct the MAC curve.[17]

Table 1. The abatement costs and potentials of each of the abatement.

Abatement route	Abatement costs	Abatement potential
	€/tCO2	*Mt CO2/year*
DRI bio CH4 pre and post-combustion CCS	13	9
DRI bio CH4 post-combustion CCS	54	56
DRI CCS	80	0
DRI bio CH4	104	27
H - DRI (20% bio CH4)	111	0
H - DRI (20% CH4)	115	38

4.2. The value of negative emissions and overview of total costs of each abatement option

Even when switching from coal in the fossil comparator to biomethane or hydrogen in DRI shafts, there is a need for carbon in the upstream pellet plant and the downstream Electric Arc Furnace. Today, coal is used in those processes and in this study we assume that this coal is replaced by biochar, which appears to be a cost-effective way to abate those emissions.[18]

Biomethane-fired DRI generates valuable negative emissions

Biomethane has a significant advantage over hydrogen and other abatement routes. Not only because biomethane is far cheaper today and can be scale up rapidly, but also the fact that biomethane facilitates can even bring negative emissions when coupled with CCS.[19] This reduces the cost associated with remaining emissions and even gives a net benefit when producing climate positive steel. These negative emissions are assumed to be valorised at the societal cost of carbon by 2040 of € 269/tCO_2 as estimated by the European Commission. [20] **Fout! Verwijzingsbron niet gevonden.** shows the value of negative emissions and the cost of remaining emissions based on the calculation of emissions per abatement route[21] and this assumed cost of carbon.

[17] See Annex II for details on primary steel, calculation of fossil comparator and explanation of abatement options.

[18] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50. See: LINK

[19] CCS is assumed at a cost of ~€112/tCO_2 , this includes €80/tCO_2 for the capture at the steel plant, €8/t CO_2 for the pipeline and €24/t CO_2 for the CCS storage underground.

[20] Societal cost of CO_2 (avoidance cost not damage cost) as used in TYNDP, based on numbers from DG MOVE. TYNDP (2022). Implementation guidelines. See LINK, p.59.

[21] Emissions calculated from fuel use as shown in Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50, and the emission factors in IPCC 2006. In a more detailed analysis the small

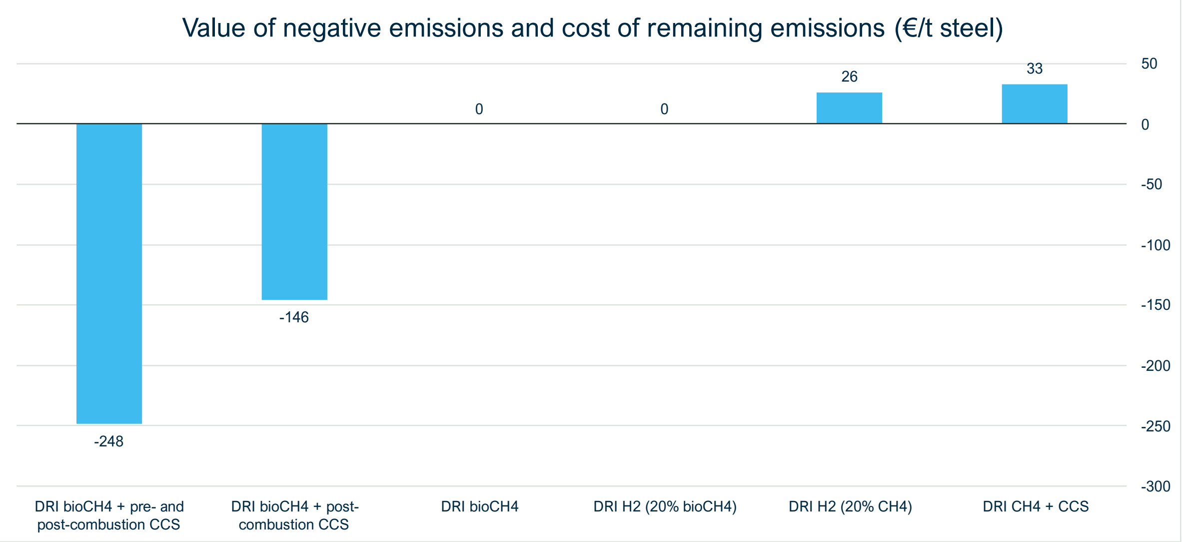

Figure 8. The value of negative emissions and cost of remaining emissions in the abatement routes for primary steel making.

The remaining emissions shown in the figure are due to the fact that some unabated natural gas is used in the hydrogen-DRI route and when combining natural gas with CCS, not all emissions can be captured.

Hydrogen deployment in DRI shaft limited due to the need for carbon in steel
As a result of the requirement for carbon in steel production the use of hydrogen in the DRI shaft can currently only be done to a maximum of 80% of the fuel injected. The remaining 20% has to be covered by a carbon rich fuel. For this analysis this report included two cases, one using 20% natural gas and the other using 20% biomethane. When using hydrogen there is an increase in the carbon requirements in the EAF, thus when making the comparison of hydrogen and biomethane fuelled DRI, there is a slight increase in biochar needed in the hydrogen fuelled DRI abatement option.

Figure shows the energy carrier demand per abatement route for primary steel production.[22] The fossil fuel comparator, BF/BOF, is also shown to show the scale of change to the inputs and the large reduction in coal use. Coal is replaced in all scenarios by biochar as a carbon source in the pellet plant and EAF for steel production, while CCS also requires an increase in electricity use compared to production without CCS. Any theoretical limit on the amount of biochar substitutable for coal has not been considered.

volumes of process emissions from dolomite and limestone breakdown could be included, along with the amount of carbon embodied into the steel, but they would to some extent cancel each other out.

[22] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50. See: LINK

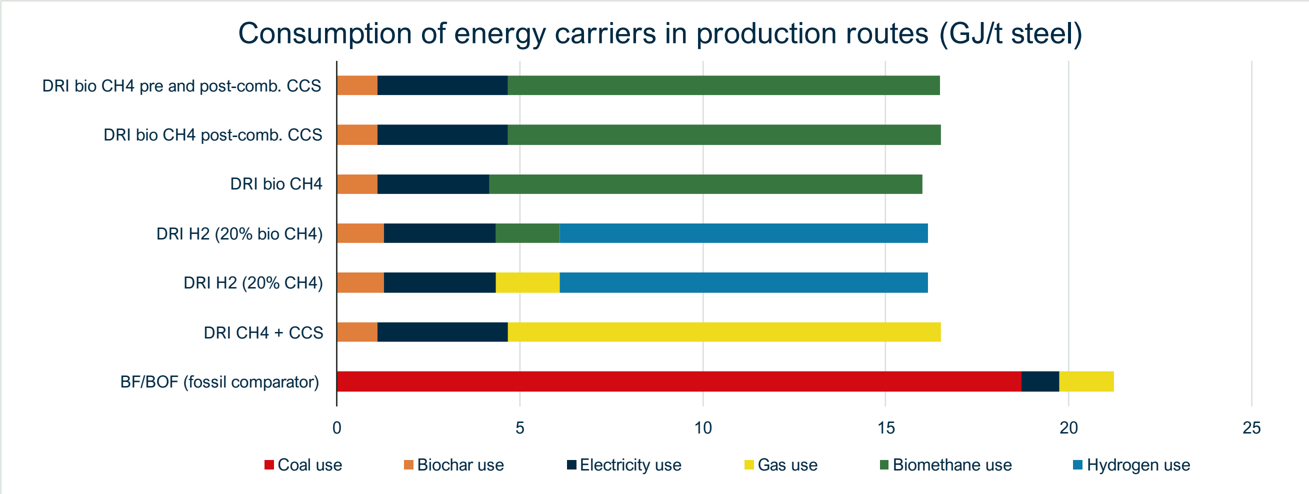

Figure 9. Fuel mix of abatement routes for primary steel making.

The value of emission reductions from biomethane use is greater than the associated cost increase from fuel switching

The investment and operating costs for biomethane use in primary steel production are comparable to other abatement routes.[23] It is notable however that the energy costs of production with biomethane are the highest of all abatement routes, at worst doubling from the lowest energy cost abatement route which uses natural gas, as shown in Figure .

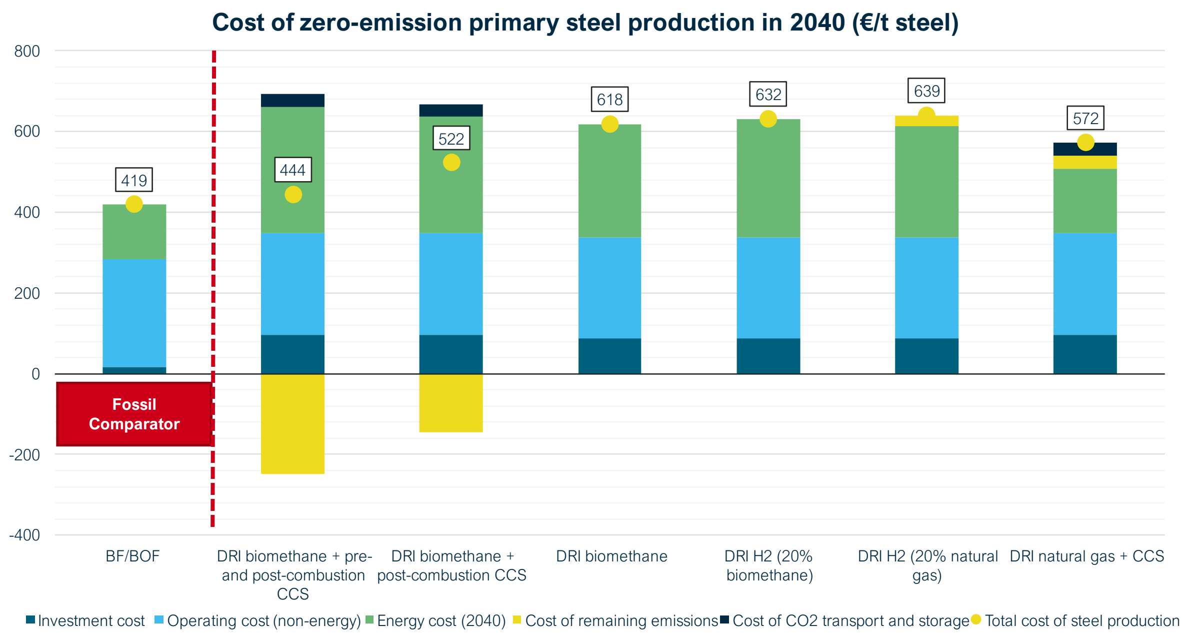

Figure 10. The cost components of the fossil comparator and the abatement routes for primary steel production.

[23] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50. All costs in €/t steel HRC. Energy costs calculated using included energetic inputs and fuel cost assumptions from chapter 2 & 3 for biomethane and hydrogen production. Natural gas is assumed to cost €30/MWh. Electricity is assumed to be emission free, and €40/MWh. **All calculations are done on a cost basis.**

5. Biomethane for carbon rich feedstock

Besides their role in meeting the industrial demand for thermal and electrical energy, fossil fuels like coal and natural gas are currently also used by industry to fulfil the demand for carbon rich feedstock in various processes. The previous chapter highlighted to crucial role of carbon rich feedstock in the production of steel. Another example is the carbon consumed in the production of chemicals and polymers in the chemical sector.[24]

Abatement options for carbon rich feedstocks in industry are limited to direct air capture, biomethane and biomass. The marginal abatement cost of base-case biomethane[25] (plus biomethane with option to generate negative emission analysed in this report) and direct air capture are visualised in Figure 13. Biomethane shows to be a more cost-effective abatement option for carbon rich feedstocks compared to direct air capture.

To determine the marginal abatement cost of these sources, natural gas was used as a fossil comparator (with a cost of €30/MWh and emissions of 0.209 tCO_2/MWh). The cost of biomethane for application in carbon rich feedstocks are limited to the production of biomethane (~€70/MWh_{th}). Direct air capture is an emerging technology for which no reliable cost data is available. Cost estimations for this technology are taken from estimates in a study of Eurelectric, which were based on studies by IEA and Zero Emissions Platform.[26] The Eurelectric study estimates the cost of direct air capture (including transport) to be in a range of €135 /tCO_2 to €358 /tCO2.

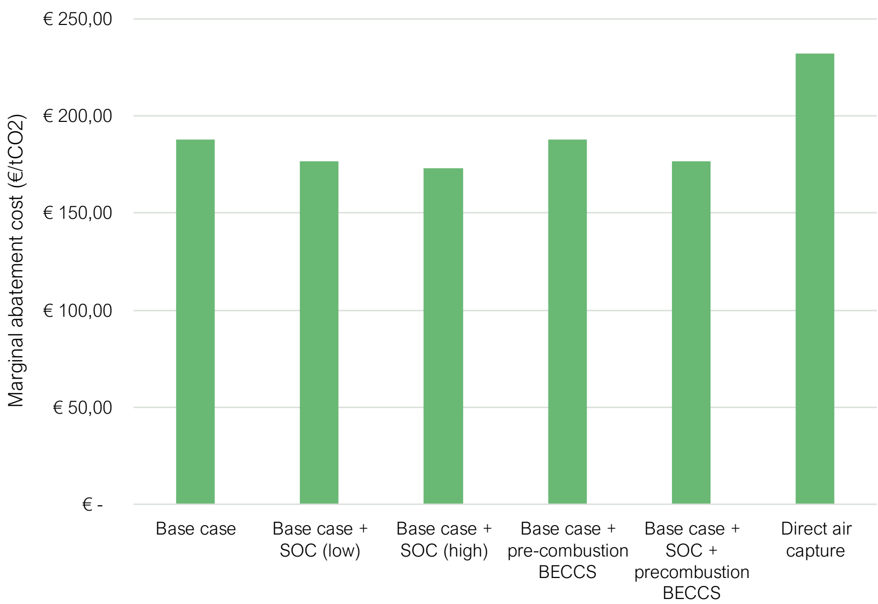

Figure 11: Marginal abatement cost of abatement options for carbon rich feedstock.

[24] Renewable carbon news (2021). How to meet the global need for carbon as a feedstock in the chemical and derived materials sector in the future. See: LINK.

[25] Biomethane produced from a mix of production pathways, being gasification (25%), and large- and small-scale anaerobic digestion (75%).

[26] Eurelectric (2023). Decarbonsiation Speedways. See: LINK, slide 73.

6. Annexes: creation of the MAC curves

6.1. Annex I - Dispatchable electricity

The analysis and comparison of the abatement cost and potential of each of the abatement options for dispatchable electricity is based on the (additional) cost for electricity generation and related energy storage. It does not include the cost of infrastructure for energy transport, which is, to the best of our knowledge, not included in the PRIMES modelling either.

Fossil fuel comparator for electricity production

To determine the abatement potential and additional cost of the options for dispatchable electricity, the model uses a fossil fuel comparator, based on the European Commission's guidelines in the EU-RED. The EC has developed the fossil fuel comparator for electricity production based on a 'basket' of fossil fuels used in the production of electricity in 2005. This basket constitutes a mix of fossil fuels, including natural gas, and coal. The emissions of the fossil fuel comparator $EC_{F(el)}$ for electricity production are 183 $gCO_{2,eq}/MJ_e$. which translates to 0.659 $tCO_{2,eq}/MWh_e$. We assumed the LCOE of fossil fuel comparator to be €60 $/MWh_e$.[27]

Calculating the MAC curve axes

The vertical axis of the MACC presents the marginal abatement cost of each of the abatement options. This is calculated by comparing their levelized cost of (dispatchable) electricity production and related marginal $CO_{2,eq}$ emissions ($/MWh_e$) with the LCOE and emissions of the fossil comparator. The horizontal axis of the MACC presents the annual abatement potential of each of the abatement options, which was calculated by multiplying the abatement potential of producing one MWh_e (compared to the fossil comparator) with the maximum potential for dispatchable electricity of the abatement option.

Abatement options included in the analysis

The abatement options for renewable dispatchable electricity analysed and compared in this report include solar PV (+battery storage), onshore wind (+battery storage), offshore wind (+battery storage), combined cycle hydrogen turbine (including electrolysis from intermittent renewable electricity), second generation nuclear, pumped hydro and the biomethane abatement options introduced in chapter 2. The potential and cost assumptions for the abatement options, excluding biomethane, are largely based on EU-wide averages in the input data for TYNDP 2024.

The required installed battery capacity for the solar PV and wind sources is scaled based on the remaining electricity demand for one week during a 'Dunkelflaute'. Remaining electricity demand here indicates the difference between the electricity demand and the electricity supply from solar PV, wind, nuclear and hydro. The remaining demand was determined based on modelling results from TYNDP 2022, which includes an hourly electricity supply profile for the year 1995.[28]

[27] Based on the CAPEX, OPEX and technology lifetime of a CCGT in TYNDP 2024, average (fossil) fuel cost of €30 /MWh, and 8,000 full load hours.

[28] TYNDP (2022). Graphs and Figures Excel. See: LINK, Sheet 29a. The 1995's 'Dunkelflaute', i.e. the period with the highest residual demand, is from December 7 until December 21.

The analysis does not include geothermal heat for dispatchable electricity production, as a dispatchable deployment of this source is not likely to be economically viable. Also 3rd generation nuclear is not included in the analysis, as TYNDP does not foresee significant capacities of this source to be installed by 2040.

6.2. Annex II – Steel production

"Primary steel" is assumed to represent 50% of the 2040 steel industry

Steel is currently responsible for 5-6% of CO_2 emissions in the EU,[29] with an emission intensity of approximately 1.9 tCO_2/t steel. Conventional steel production is energy intensive using ~ 19 GJ coal as a fuel and feedstock per tonne of steel produced in a Blast Furnace - Basic Oxygen Furnace (BF-BOF) and with iron ore as its dominant source of iron. As raw iron ore is the main iron source this production method is termed "primary steel production". Primary steel accounted for 57% of steel production in the EU in 2022.[30] The other 43% of steel production is using scrap steel as the main iron input into Electric Arc Furnaces (EAF). Because this production route relies on the recycling of the current steel stock it is termed "secondary steel production". As recycling of steel increases in time, EAF based production is assumed to increase its share of the production capacity to about 50% of total production by 2040, leaving 50% of the market to be filled by primary steel. The total market size is assumed to remain the same as in 2022 and have production volumes of ~135 Mt steel/year.[18] With a full decarbonisation of the 68 Mt steel/year primary steel approximately 129 Mt CO_2 are abated.

Secondary steel production can achieve net zero emissions largely based on decarbonisation of the power mix. Biomethane is not used directly in EAFs albeit can play a role in the net zero emissions electricity mix as shown in this report. Because no biomethane will be used directly for secondary steel, this report focuses on the abatement options for primary steel.

Scope of the work includes some upstream and downstream processes

This report builds off data in a study by PBL, the Netherlands Environmenal Assessment Agency, (2021)[31] keeping the same scope with all calculations done per tonne of hot rolled coil (HRC), the most common finished steel product in the EU in 2023.[32] In line with the PBL study this analysis includes the pellet plant and oxygen plant in the upstream, and the downstream steelmaking processes required to produce HRC.

The "ULCORED ± CCS" technological option is chosen as the technology for each of the abatement routes in this analysis. This is a deviation from the source report, as the "H-DR" route in PBL (2021) considers a technology with a TRL of 5, and though the development of this route is the subject of much research currently, e.g. HYBRIT,[33] we chose not to include this technology in our analysis, but instead the already mature "ULCORED ± CCS". With this chosen technology route the substitution of up to 80% of the natural gas requirements with hydrogen is assumed to be possible. This meaning our

[29] European Parliament (2021). Carbon-free steel production See: LINK
[30] EUROFER (2023) European steel in figures 2023 page 15. See: LINK
[31] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry
[32] EUROFER (2023) European steel in figures 2023 page 18. See: LINK
[33] HYBRIT. See: LINK

hydrogen steel abatement routes require 20% methane in the DRI shaft, either from natural gas or biomethane.[34]

Fossil fuel comparator for primary steel production
Primary steel production uses coking coal in a blast furnace (BF) to heat up iron ore, typically in sinter and pellet form, to over its melting point to a temperature of ~ 1300°C. The CO and H from the coal combustion then reduce the iron ore, to make "pig iron". This pig iron is put into the basic oxygen furnace (BOF) where oxygen is used to remove some of the carbon content of the pig iron, and additives are used to remove impurities and turn it into a steel product.

The emissions from this production pathway are approximately 1.9 t CO2/t steel, and are largely a result of the large coking coal demand of ~ 19 GJ/t steel and other energetic inputs from natural gas and electricity production. As the fossil comparator is an existing plant we assume that the capital costs have been repaid and thus the only investments needed for the facility are for relining. Using relining costs from work by Agora Industry,[35] and other cost data from the primary source of data for this analysis [36] the production cost was determined to be €418/t Hot Rolled Coil (HRC) steel. This is likely an underestimate of the cost of relining as downtime will be costly for steel plants with approximately 4 months of lost revenues typically incurred from this relining downtime. [37]

Main abatement options for primary steel
The mature abatement options for primary steel production giving significant emission reductions are either combining the existing BF-BOF installations with CCS, or transitioning to DRI production installations. DRI production can be done with either natural gas with CCS or renewable gases (hydrogen and biomethane), that can also be combined with CCS. All DRI production is coupled with an EAF to create the crude steel product. All abatement routes also use biochar in place of coal with 100% substitution assumed to be technically possible.

BF/BOF with CCS: This abatement option uses the current production method with the large energetic input being in the form of coking coal. CCS is applied to several parts of the supply chain e.g. the blast furnace and the steam generation plant, however, other parts of the supply chain are more difficult to capture the emissions from. **This leads to a total capture rate of 55%.[38] As a result this abatement route is not considered in this report.**

DRI ± CCS ± renewable gases: This abatement option uses the technologically mature DRI shaft with an EAF to produce steel. Natural gas is used today in DRI shafts globally to produce steel, however as this **only reduces emissions by approximately 60%, DRI with natural gas alone is not considered in this report.**

[34] Roland Berger (2020). Feasibility study on climate-neutral pathways for TSN IJmuiden. See: LINK
[35] Agora Industry, Future Camp, Wuppertal Institut (2022). Carbon Contracts for the transformation of industry: Calculator for the assessment of transformation costs for low-CO_2 primary steel production. Model version 1.1, Berlin, 16.12.22. See: LINK
[36] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50
[37] ArcelorMittal (2020). See: LINK. Accessed on: 12/03/2024
[38] IEA (2013) Iron and Steel CCS study (technoeconomics integrated steel mill). page 6, average of case 2A and 2B. See: LINK

To further reduce emissions DRI shafts can be combined with CCS and or fuel switching away from natural gas. Fuel switching to hydrogen has been highlighted by many studies as a key green steel production method. As mentioned above, currently 20% of the energy input to the DRI shaft will require a carbon rich fuel so methane is considered in all cases. Biomethane use can offer the potential to reduce emissions further either in this process with hydrogen as 20% of the fuel mix for DRI, or as a full replacement for natural gas. Biomethane use can also be coupled with CCS where hydrogen cannot, and as such negative emissions can be achieved with both post combustion CCS at the DRI shaft, and pre-combustion CCS at the biogas upgrader.

The resulting abatement options for primary steel production considered in this report are:

Abatement route
DRI CCS
H - DRI (20% CH4)
H - DRI (20% bio CH4)
DRI bio CH4
DRI bio CH4 post-combustion CCS
DRI bio CH4 pre and post-combustion CCS

Calculating the MAC curve axes for steel

The vertical axis of the MACC presents the marginal abatement cost of each of the abatement options. This is calculated by comparing their levelized cost of steel production and related marginal $CO_{2,eq}$ emissions (/t steel HRC) with the cost of steel production and emissions of the fossil comparator. The horizontal axis of the MACC presents the annual abatement potential of each of the abatement options, which was calculated by multiplying the abatement potential of producing one t steel HRC (compared to the fossil comparator) with the maximum potential for steel of the abatement option.

Not considered in this report is the potential to avoid the use of coal in the steel production process. Instead this report consider the changes to the main energy carrier the significant levers towards zero emission steel production. The use of charcoal in place of coal can provide emission reductions however, with some analysis on the potential found in the cited PBL study.[39]

6.3. Annex III – Energy costs

In general energy cost assumptions were taken from TYNDP advice. These numbers were complemented with assumptions where needed, and recent work from EU supported work.

Energy source/carrier	Cost	Source
Average electricity production from renewable sources (solar and wind)	€ 40 /MWh_e	TYNDP (2024). Excel workbook - Draft supply inputs for TYNDP 2024, sheet 2.1. See: LINK
Electricity production from 2nd gen. nuclear (assuming 4,380 FLH)	€ 33 /MWh_e	Energy transition model, see: LINK

[39] Netherlands Environmental Assessment Agency (2021). Decarbonisation options for the Dutch steel industry p. 46, 49, & 50. See: LINK

Electricity production from pumped hydro (assuming 4,380 FLH)	€ 25 /MWh_e	Energy transition model, see: LINK
Hydrogen (assuming 4,000 FLH)	€ 65 /MWh_{th}	TYNDP (2024). Excel workbook - Draft supply inputs for TYNDP 2024, sheet 2.1. See: LINK
Biomethane	€ 70 /MWh_{th}	Average of work from BIP Task Force 4.2 (2023) Insights into the cost of biomethane production using real industry data. See: LINK, and gasification cost from Gas for Climate, the optimal role for gas in a net-zero emissions energy system (2019). See LINK
Natural gas	€ 30 /MWh_{th}	Assumption
Coking coal	€ 25 /MWh_{th}	TYNDP (2020). Fuel commodities and carbon prices. See: LINK
Biochar	€ 43 / MWh_{th}	Hakala et al., (2019). Prospects for the use of biomass in steel industry. See: LINK p94 Scenario L1. 34 GJ/t biochar HHV taken, Table 4, p20

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