

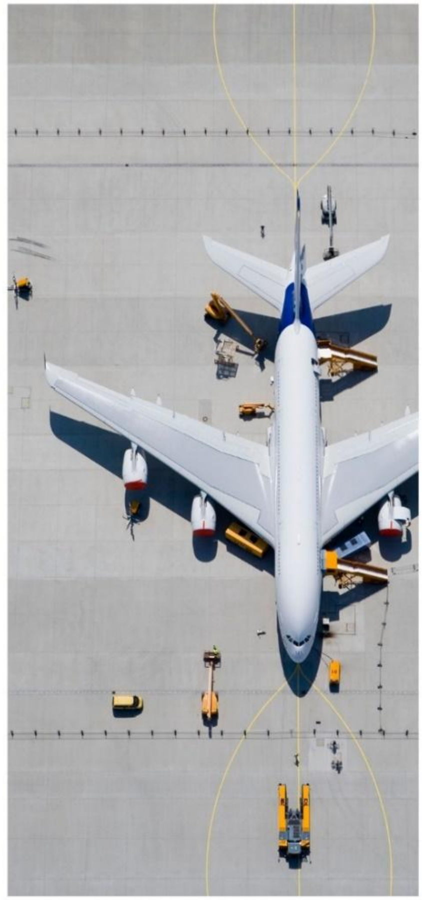

CI Consulting

Study on the potential evolution of Refining and Liquid Fuels production in Europe

February 2025

Concawe
Environmental Science for European Fuel Manufacturing

S&P Global
Commodity Insights

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This study evaluates the impact on the refining and fuel manufacturing industrial assets of two hypothetical scenarios which both meet the net zero GHG emission objective by 2050 in EU27 + 3 European countries (NO, CH, UK). Both scenarios share a common basis for the transition of most economic sectors but differ on the decarbonization pathway of the transport sector.

The first, the “**Max Electron Scenario**” meets all requirements of the Fit for 55 package while surpassing the Heavy Duty Vehicles CO_2 standards regulation requirements by assuming zero sales of ICE vehicles after 2035 and assumes an accelerated and unprecedented rate of electrification across various modes of transportation.

The second, the “**More Molecule Scenario**” has been derived from the Max Electron Scenario by relaxing the requirements of the LDV and HDV vehicle standards and allowing sales of some new internal combustion engine cars and vans after 2035 and postponing any electrification in the aviation and marine sectors to after 2050. In this way, this scenario achieves net zero in 2050 by complementing electrification with an increased use of low carbon fuels.

Neither scenario is intended as a validation of the probability or feasibility of realising the various assumptions in the study, such as the rate of electrification or availability of renewable energy and green hydrogen for the transport sector, nor do they assess the impact on competitiveness of the European economy or the affordability for consumers or industries. These scenarios are two theoretical cases to meet the EU 2050 net zero objective.

The choice of these two theoretical scenarios should not be considered as exhaustive to meet the 2050 net zero emission objective, as this study does not include other scenarios which could potentially achieve the objective by modifying further other key decarbonization opportunities, such as, for example, even greater uptake of carbon capture and storage (CCS), additional bioenergy carbon capture and storage (BECCS), blue hydrogen or other technological advancements in other sectors than transport.

Furthermore, the economic modelling behind the scenarios did not take into account refinery specific parameters, such as petrochemical integration, individual refinery energy efficiency, etc. The conclusions regarding the necessary reduction of refining capacity should therefore not be interpreted as an indication at the level of any individual European refinery.

1 Introduction

Concawe has engaged S&P Global Commodity Insights (SPGCI) to analyse the potential impact of the EU's target to achieve net-zero emission by 2050 on the region's refining industry and security of supply under two scenarios.

Concawe was established in 1963 by a group of leading European oil companies to carry out research on environmental issues relevant to the hydrocarbon industry. Its membership has broadened to include most oil companies operating in Europe. Concawe is a division of the European Fuel Manufacturers Association.

Concawe has already studied opportunities and challenges with regard to the future of the EU refining industry amid the ongoing transition to a low CO_2-intensive economy up to 2030 and 2050, and published different scenarios, including considering increase in the production of low-carbon fuels, such as sustainable biofuels and e-fuels, in its Refinery 2050 report:

> Refinery 2050: Conceptual Assessment. Exploring opportunities and challenges for the EU refining industry to transition towards a low CO_2-intensive economy (September 2019)

The focus of SPGCI's study, which was undertaken in collaboration with the National Fuel Industry Associations, was to increase the granularity of the scenarios to better model the possible socio-economic consequences of the different scenarios on EU+ countries, i.e. the 27 EU countries plus Norway, the UK and Switzerland.

The objective is to assist stakeholders to better understand the possible implications of the energy transition by providing two different scenarios with regard to mobility and energy supply, with segregation by clusters of EU+ states.

This will provide a deeper understanding to EU+ states on the subject, enabling them to take the required measures for a smooth and value-added transition to climate neutrality, without disturbing free market mechanisms, and without undermining the security of supply of fuels and other refinery products of key importance for the economic value chain of the EU+ states. It also addresses potential fuel supply issues that could impact fuel security during the energy transition phase.

SPGCI's study scope comprised:

Task 1: Summary of key legislation – Section 3 of this report

Task 2: Scenario modelling – Section 4 and Appendix A

Task 3: Refinery Linear Programme modelling – Section 5

Task 4: Supply modelling – Section 6

Task 5: Security of supply analysis – Section 7

2 Executive Summary

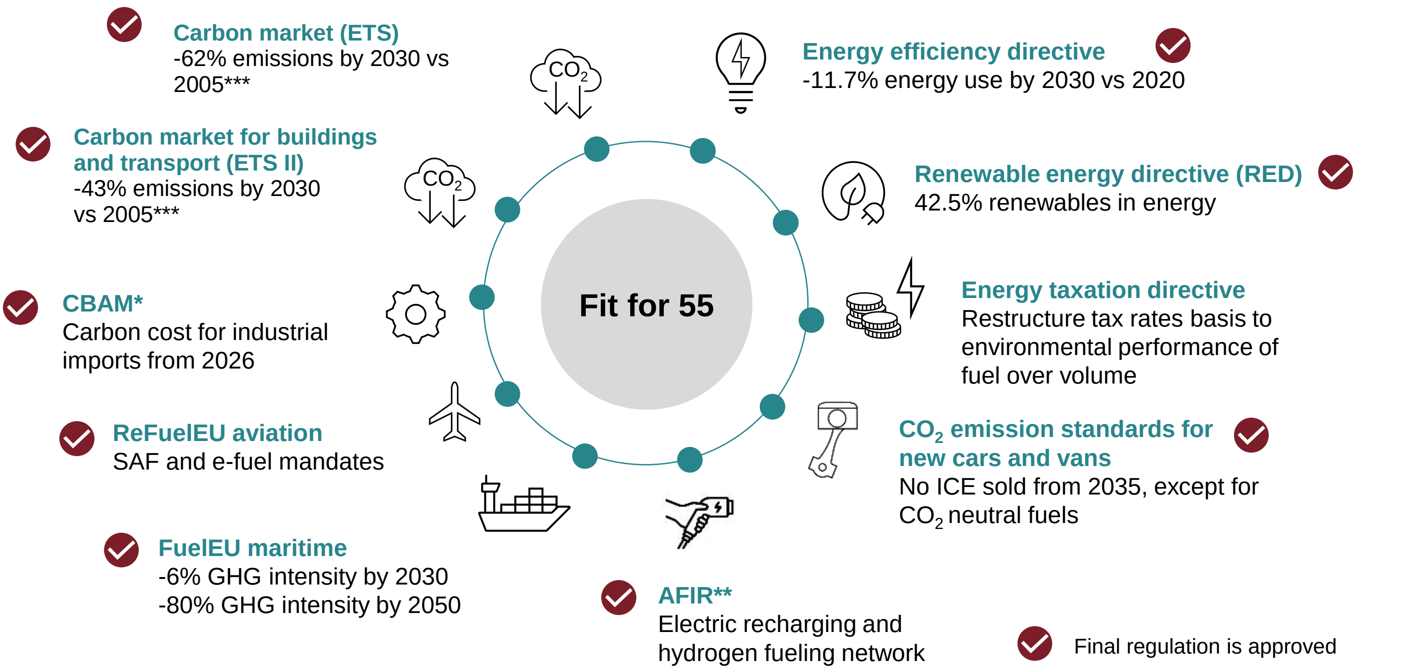
2.1 EU Legislation review

The European Green Deal, presented by the European Commission in December 2019, is a set of policy measures aimed at promoting environmentally sustainable development and economic growth across the European Union (EU) with the overarching goal of achieving climate neutrality by 2050. It covers all sectors of the economy, including transport, energy, agriculture and industry, with actionable policies aimed at reducing emissions and promoting energy transition.

The European Climate Law transforms the European Green Deal's political commitment into a legal obligation and details the necessary steps to get there.

EU member states and the European Parliament approved the European Climate Law on 29 July 2021. By adopting it, the EU and its member states committed to the intermediate target of cutting net greenhouse gas (GHG) emissions in the EU by at least 55% by 2030, compared with 1990 levels. This 55% reduction is covered by the 'Fit for 55' package, proposed in July 2021. The package is summarised in Figure 2.1 below.

Figure 2.1: Fit for 55 policy initiatives



SAF = Sustainable aviation fuels; ICE = Internal combustion engine; GHG = greenhouse gas.

* CBAM: Carbon Border Adjustment Mechanism

** AFIR: Alternative Fuels Infrastructure Regulation

*** The release for consumption of fuels for which the emission factor is zero, is not considered in the scope of ETS and ETS II. Under the ETS Monitoring and Reporting Regulation ('MRR'), the zero rating applies to renewable fuels compliant with the RED (Biofuels, RFNBOs and RCFs), as well as low carbon fuels defined in Article 2 (13) of the Gas Directive and certified according to the provisions set by Article 9.

Sources: European Commission and S&P Global Commodity Insights

2.2 Scenario modelling

Our Energy and Climate Scenarios are typically used by clients for the creating and testing of strategy. Green Rules is our current view of the fastest plausible energy transition, but it is not net zero globally, and results in a global temperature rise of +1.7°C by 2100. Green Rules is however essentially net zero when looking at Europe by 2050.

For this study S&P Global created two bespoke scenarios – **Max Electron** and **More Molecule**. Both used the Green Rules scenario from the SPGCI Energy and Climate Scenario service as a start-point.

Max Electron:	Meeting the net zero GHG emission objective by 2050 for the EU+ set of countries, strictly meeting all requirements of ‘Fit for 55’ and heavy-duty vehicles CO_2 standards, achieved via an accelerated rate of electrification across various modes of transportation, more aggressive than Green Rules.
More Molecule:	Meeting the net zero GHG emission objective by 2050 for the EU+ set of countries, reaching the requirement of RefuelEU Aviation and FuelEU Maritime, achieved for road transport via a combination of a high degree of electrification and with some remaining sales of internal combustion engine (ICE) vehicles after 2035, with increased substitution of traditional fuels by renewable fuels, but overall, less electrification than in the Max Electron scenario.

Both scenarios rely on an important shift of road and aviation transport to rail. The increase in rail activity required to meet net-zero emission objective in 2050 represents a major challenge, which will require significant investment in the rail infrastructure.

Comparing the overall total energy demand for More Molecule and More Electron scenarios by 2050, the More Molecule scenario requires 65 MMtoe more energy demand as compared to Max Electron scenario by 2050.

2.3 LP analysis

The Max Electron and More Molecule scenarios present significant numerical shifts in the EU+ region's refinery landscape, driven by S&P proprietary forecast of industrial and transport activity, by the adoption of e-mobility and the transition to low carbon fuels. These transformations are poised to reshape oil demand, traditional refining capacities and product balances, necessitating strategic adaptations from the refining industry, and its transition to low carbon fuels manufacturing.

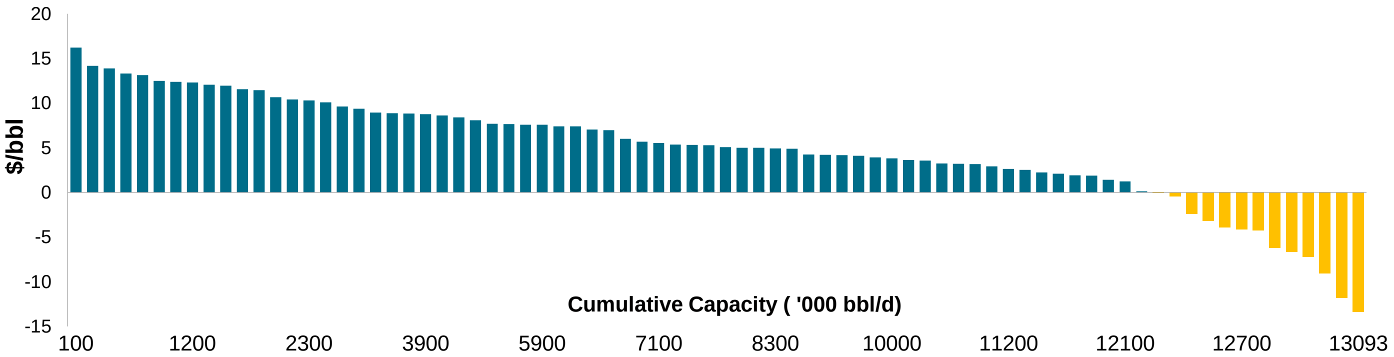
S&P Global developed a Linear Progam (LP) model, in which all EU+ refineries are represented. The LP output for 2024 is almost identical in both scenarios and is shown in Figure 2.6. The 2050 refinery margin curves are shown in Figures 2.7 and 2.8 respectively.

Key point: the adoption of electric and hybrid vehicles is anticipated to significantly reduce fossil fuel demand by 2050, altering the net trade position of refined products. While the EU+ region currently stands as a relatively balanced market for refined products (although requiring gasoline exports and middle distillate (kerosene, diesel) imports), both scenarios foresee a substantial decline in the EU+ region fossil fuel demand resulting in a massive reduction in required traditional refining capacity by 2050.

Economic factors significantly impact conventional refinery viability, with LP model outputs showing increasing numbers of EU+ refineries projected to have negative margins over time under both scenarios. Refineries showing negative margins are deemed to stop operations.

Existing refineries will have to align their capacities with lower margins resulting from decreasing market demand, with a particular focus on exploring the processing of low-carbon feedstocks and hydrogen options to meet sustainability goals. Conventional refining capacity is projected to decrease from 13 million barrels per day (MBPD) in 2024 to 2.1 MBPD in More Molecule and 1.7 MBD in Max Electron by 2050. This significant reduction reflects the negative margins due to the declining fossil fuels demand and the corresponding need for refineries to adjust their operations to match market dynamics.

Figure 2.2 – EU+ Fossil Refining Net Cash Margin Forecast 2024 (constant 2022)



Margins include emission costs
Source: S&P Global Commodity Insights.
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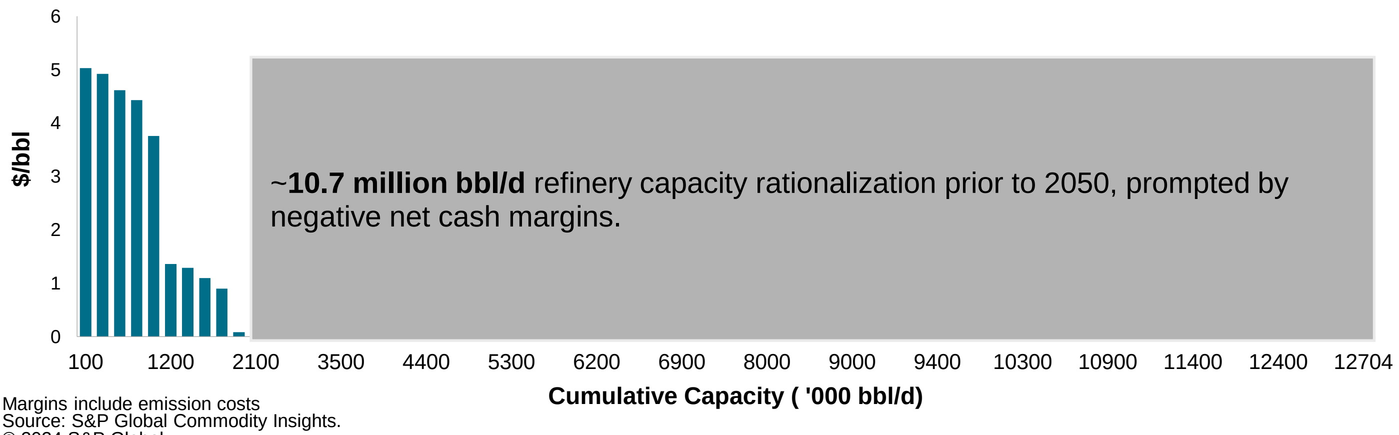
Figure 2.3 – EU+ Fossil Refining Net Cash Margin Forecast 2050 (constant 2022): More Molecule



Margins include emission costs
Source: S&P Global Commodity Insights.
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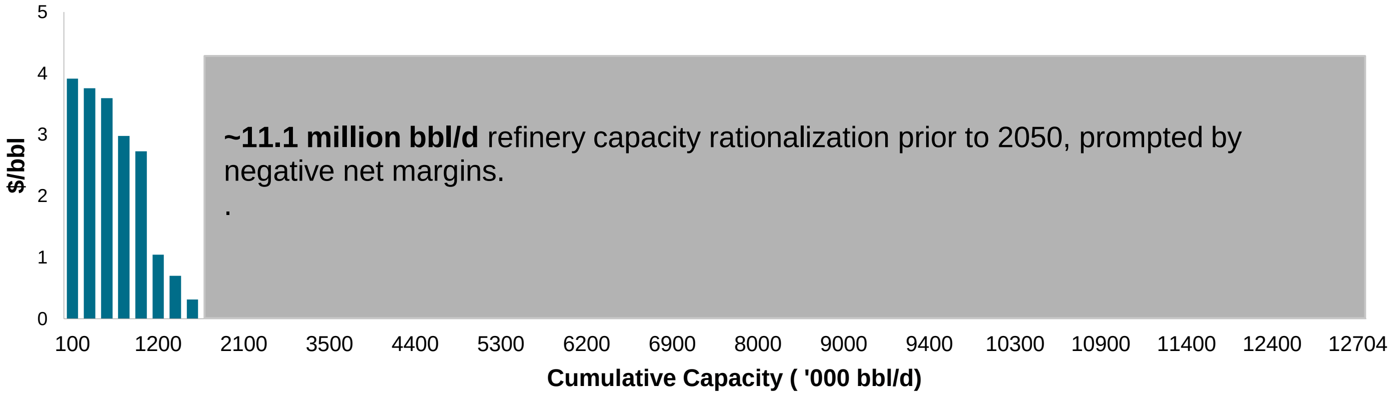
Figure 2.4 – EU+ Fossil Refining Net Cash Margin Forecast 2050 (Constant 2022): Max Electron



Margins include emission costs
Source: S&P Global Commodity Insights.

In both cases significant conventional refinery closures are expected. However, the demand for low carbon fuels is higher in the More Molecule scenario, which creates greater opportunity for traditional refineries to be transformed to produce low carbon fuels rather than being fully closed in this scenario.

2.4 Supply and demand

In both scenarios EU+ demand for conventional hydrocarbons falls and the region enters a sustained period of having an excess of crude oil refining capacity. However, expected poor refining economics restricts the operating rate of conventional refineries and as a result refining cover[1] for most fuels reduces over 2024 to 2040.

It is after 2040 when the rationalization of refineries results in conventional refining cover for naphtha, LPG, jet fuel/kerosene and fuel oil falling below 100% (albeit for much smaller demand volumes than in 2024-2040). EU refining cover for fossil gasoline and diesel is high due to the very low demand for these fuels.

In the Max Electron and More Molecule scenarios, food and feed crop-based biofuels production capacity will enter long-term decline in line with falling fuel demand. It will furthermore fall to zero by 2050 to meet net zero emissions because of the higher embedded CO_2 content of food and feed crop-based biofuels. Annex IXB biofuels production capacity will also decline in line with falling fuel demand, in 2050 production is 5.2 MMtoe in Max Electron and 5.7 MMtoe in More Molecule.

In both scenarios, production capacity for Annex IXA biofuels needs to increase in the long-term to meet the rising demand for advanced biofuels. By 2050 in the Max Electron scenario, production capacity needs to rise to ±57 MMtoe, and to ±88 MMtoe in the More Molecule scenario.

[1] Refining cover: ability of EU+ refining to supply EU+ demand

The Imperial College Report[2] showed that the potential availability of advanced and waste-based biofuels (through EU domestic production) in 2050 can reach 137 MMtoe with some progress in biomass collection and R&D in yield improvement. The demand for biofuels in the Max Electron scenario falls within the low to middle of sustainable biofuel potential availability, whereas the More Molecule scenario approaches the upper range of this estimate. This implies that improvement measures will be required to realise the higher mobilization of biomass required.

SPGCI maintains a database of fatty acid methyl esters (FAME) plants, fuel ethanol plants and bio-refineries which is updated by the SPGCI Biofuels Value Chain Service (BVCS) team of researchers and analysts. This database records global biofuel plants that are operating and the projects that have been announced publicly by companies in the industry up to 2030. Collectively between the FAME plants, fuel ethanol plants and bio-refineries – considering both current operational capacity and firm projects - EU+ biofuel production capacity is forecast at 33 MMtoe/a in 2030. We assume that two-thirds of this capacity will remain operational in 2040 and 2050.

As fossil fuel demand reduces, the use of spare capacity in the existing refining infrastructure provides a useful path to produce biofuels. Our analysis allows spare capacity on operational diesel/kerosene hydrotreaters to be used to produce biofuels, either by co-processing, or produced in batch with fossil fuels. We also assume that refineries which are stopping their fossil operations can be re-purposed to produce advanced biofuels. This greatly reduces the requirement for investment in new stand-alone biofuel or e-fuel plants and would likely reduce overall investment costs as the re-purposed plant could take advantage of existing infrastructure on the refinery sites and access existing fuel distribution networks.

By 2050, assuming a standard capacity for biorefinery of 1MMtoe/a, the EU+ would require 22 re-purposed or new biorefineries in Max Electron scenario and 48 in More Molecule scenario to supply the required biofuel demand (Figure 2.5). This is in addition to co-processing biofuels on any remaining operational conventional refineries.

In both scenarios, demand for renewable fuels of non-biological origin (RFNBO) - hydrogen and e-fuels - grows in the long term as a solution for emissions reduction in hard to abate sectors. RFNBO also represents a way to store renewable power and to cope for the intermittency of renewable power generation. More Molecule RFNBO demand is 11% higher than Max Electron scenario by 2050. Overall possible supply of RFNBO in the EU+ is 111 MMtoe by 2050.

Excluding drop-in e-Fuels, the emergence of RFNBOs as a green energy carrier requires development of specific transportation infrastructure for import and use. Multiple hydrogen carriers exist (hydrogen gas, ammonia, methanol etc.), each with different transportation economics. In the Max Electron scenario, non-e-Fuel RFNBO demand is 151 MMtoe, and in More Molecule scenario is 160 MMtoe in 2050.

A summary of the number of refineries, biorefineries and e-fuel plants for the Max Electron and More Molecule scenarios for 2024, 2030, 2040 and 2050 for the respective country groupings for each year is provided in Figure 2.5.

[2] Sustainable Biomass Availability in the EU, to 2050 (Imperial College of London Consultants, 2021)

Figure 2.5 Number of refineries, biorefineries and e-fuel plants for Max Electron and More Molecule scenarios

Max Electron

	No. of conventional refineries running	No. of new biorefineries required	No. of efuel plants required	Total
2024	86			**86**
2030	58	0	1	**59**
2040	28	0	2	**30**
2050	12	22	11	**45**

More Molecule

	No. of conventional refineries running	No. of new biorefineries required	No. of efuel plants required	Total
2024	86			**86**
2030	59	0	1	**60**
2040	29	8	3	**40**
2050	14	48	17	**79**

2.5 Security of supply

Based on SPGCI analysis, the EU+ maximum potential for additional renewable electricity production from 2024 is estimated at ±3712 TWh in 2050, of which 51% will be used for hydrogen production in 2050. Domestic generation of RFNBO (hydrogen and e-fuels) requires additional renewable electricity of more than 1884 TWh in 2050 which will be a challenge - for context 2022 EU+ total electricity consumption was 2895 TWh.

In the Max Electron scenario, total liquid biofuel demand of bio-gasoline, biodiesel, bio-jet and bio-LPG reaches 62 MMtoe by 2050. For More Molecule, total liquid biofuel demand reaches 94 MMtoe. There is sufficient biomass available in the EU+ (Imperial College, 2021) to meet Annex IXA and Annex IXB biofuel demand and so there could be sufficient domestic production to meet these requirements without imports by 2050 under both the Max Electron and More Molecule scenarios. Such a demand of Biofuels would enhance EU+ fuel security.

In More Molecule scenario, by 2050, e-Fuels demand which includes e-SAF, e-Gasoline and e-Diesel, is 39.5 MMtoe and 23.6 MMtoe in the Max Electron scenario. Overall supply capacity for e-fuels in EU+ grows to 16.0 MMtoe in More Molecule case and 10 MMtoe in Max Electron case.

RFNBO production requires large amounts of renewable electricity from a combination of wind and solar power. It is expected that, in order to be economical, most of EU+ production will be in its southern regions: much of the EU+ region does not have enough consistent sunlight days to make such production competitive with other regions of the world. Therefore, the EU+ remains net importer of RFNBO and e-Fuels in both scenarios. By 2050 RFNBO import volumes vary from 32% in Max Electron to 39% in More Molecule of total RFNBO demand.

In 2030 and 2040, the imbalances between supply and demand of liquid fuels (fossil, bio- and e-fuels) in EU+ remain relatively similar for both scenarios: significant excess of gasoline and deficit of diesel in 2030, somewhat reduced in 2040 but countered by a significant deficit in jet/kerosene (approximately a third of the demand will have to be imported).

EU+ will have to rely on imports to cover 56% of its e-fuel demand in 2050 in the Max Electron scenario and 59% in the More Molecule scenario. It is expected that e-fuel imports will come from regions with high sunlight days and low population density, such as the Middle East, North Africa, Chile, Australia and the US Gulf Coast. Import of e-fuels could happen either as finished products or as e-crude to be refined in EU refineries, depending on the business model of the international e-fuel producers.

In 2050, both scenarios show a similar excess, although much reduced volume of gasoline. Deficit of jet/kerosene will represent 25% of the demand in the More Molecule scenario and 33% of the demand in the Max Electron scenario. Diesel will have to rely on export of approximately 20 % of its production and Residual Fuel oil and LPG on imports of approximately 50% of the demand in the Max Electron scenario while the supply and demand of these products are almost equilibrated in the More Molecule scenario, leaving the EU+ almost autonomous for these products.

The transition from fossil fuel refining results in a decline in EU+ supply of crude-derived specialty products such as bitumen, petcoke, base oils, and petrochemical feedstocks such as naphtha, propylene, and aromatics. Bitumen and petcoke cannot be cost effectively produced from renewable feedstocks and EU+ will have to rely on imports for the majority of supply in 2050. Approximately 50% of Base Oil demand will have to be imported in the Max Electron scenario (1.7 MMtoe), while these imports are reduced to approximately 35% of the demand in the More Molecule scenario (1.2 MMtoe).

The reduction in propylene and aromatics production from conventional refineries could be replaced by additional production from the petrochemical industry, which would require additional naphtha supply to steam crackers. This additional 12 MMtoe naphtha demand could be met in 2050 in the More Molecule scenario while it would have to rely on imports in the Max Electron scenario.

3 Summary of Key European legislation on reduction of GHG emissions

This chapter summarises the current European (EU+) legislation that is primarily directed towards reducing CO2 GHG emissions. Note it does not cover supporting mechanisms such as the Energy Taxation Directive, EU Methane Regulation, EU Taxonomy Regulation.

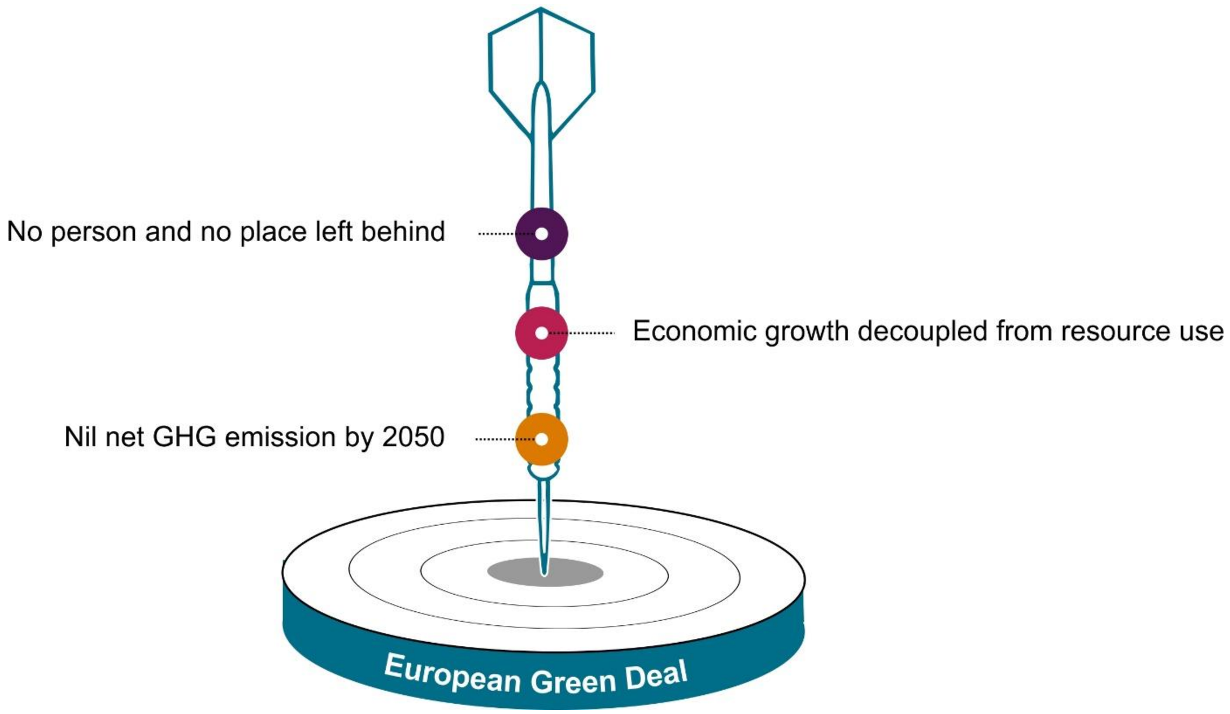
3.1 The European Green Deal

The European Green Deal, presented by the European Commission in December 2019, is a set of policy measures that aim to promote environmentally sustainable development and economic growth across the European Union with the overarching goal of achieving climate neutrality by 2050.

The European Green Deal covers all sectors of the economy including transport, energy, agriculture, and industry and aims to provide actionable policies that reduce emissions and promote the energy transition across these sectors.

The European Commission has outlined the following three aims of the European Green Deal:

Figure 3.1 – European Green Deal

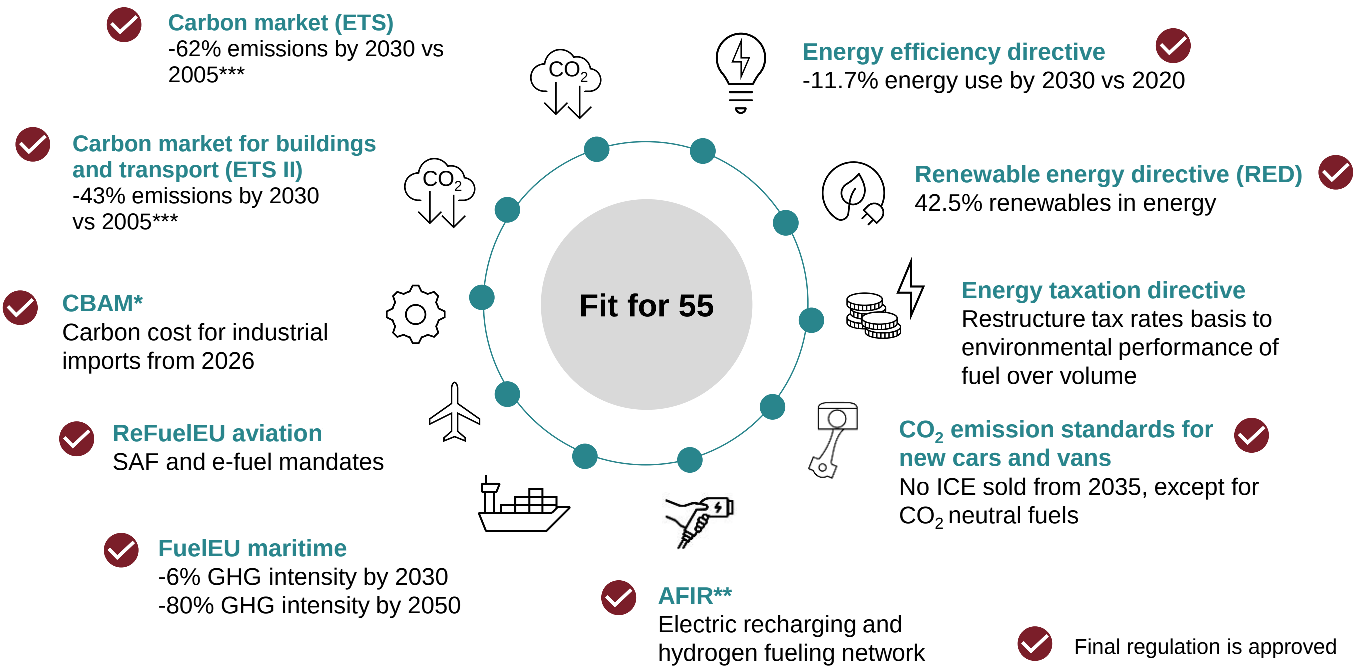


The European Climate Law turns the political commitment of the Green Deal into a legal obligation and details the steps needed to get there. On 29 July 2021, EU Member States and the European Parliament approved the European Climate Law. By adopting it, the EU and its Member States committed to the intermediate target of cutting net greenhouse gas emissions in the EU by at least 55% by 2030, compared to 1990 levels.

3.2 Fit for 55

In line with meeting the legal obligation set about by the European Climate Law, the European Commission adopted a set of proposals to ensure that all sectors of the EU's economy are able to meet the intermediate target of a 55% reduction in greenhouse gas emissions by 2030 vs 1990 levels. This "Fit for 55" package was presented by the European Commission on 14 July 2021 and includes revisions to existing policies, such as the Renewable Energy Directive II and the EU Emissions Trading System (EU ETS), as well as introducing new regulations such as the ReFuelEU Aviation and FuelEU Maritime regulations that aim to reduce emissions in the aviation and maritime sectors, respectively. It also includes revised requirements for the tank-to-wheel CO_2 emissions for the sales of new passenger cars and light commercial vehicles.

Figure 3.2 – Fit for 55 policy initiatives



SAF = Sustainable aviation fuels; ICE = Internal combustion engine; GHG = greenhouse gas.

*CBAM: Carbon Border Adjustment Mechanism

**AFIR: Alternative Fuels Infrastructure Regulation

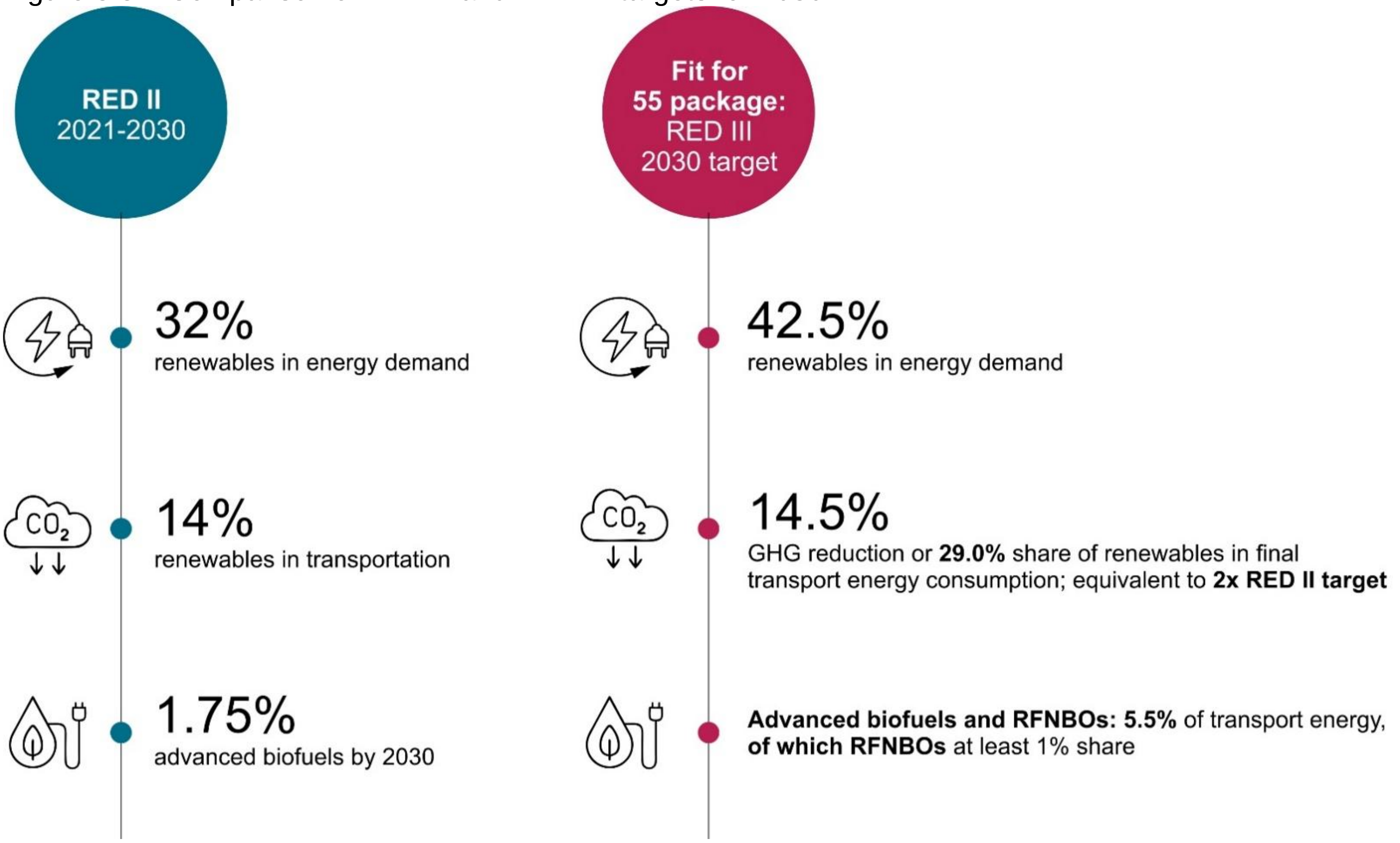
*** The release for consumption of fuels for which the emission factor is zero, is not considered in the scope of ETS and ETS II. Under the ETS Monitoring and Reporting Regulation ('MRR'), the zero rating applies to renewable fuels compliant with the RED (Biofuels, RFNBOs and RCFs), as well as low carbon fuels defined in Article 2 (13) of the Gas Directive and certified according to the provisions set by Article 9.

Sources: European Commission and S&P Global Commodity Insights

3.2.1 Renewable Energy Directive (RED)

One of the key features of the Fit for 55 policy initiatives was the revision of the Renewable Energy Directive II, often called RED III. The new Renewable Energy Directive raises the 2030 target for the share of renewable energy in the EU's overall energy consumption from 32% to 42.5%. New or increased sector sub-targets for transport, industry and the buildings sector were introduced to accelerate the integration of renewables in sectors where uptake has been slower. In transport, Member States can choose between a binding target of a 14.5% reduction of greenhouse gas intensity from renewables put on the market by 2030 or a binding share of 29% of renewables within final energy consumption in transport. Advanced biofuels and renewable fuels of non-biological origin (RFNBOs) have a new combined target of a 5.5% share and within this target there is a 1% minimum requirement for RFNBOs by 2030. The final agreement on the amendment of RED II, (RED III), was adopted by the European Council in October 2023.

Figure 3.3 – Comparison of RED II and RED III targets for 2030



Notes: RFNBO = Renewable Fuels of Non Biological Origin
The above inclusive of multipliers to the accounting of energy shares
Source: S&P Global Commodity Insights.

Table 3.1 – RED II final revisions as part of F55

RED II final revision (RED III) as part of the F55 package	
Definition of energy in transport ('numerator')	Road, rail, maritime and aviation
GHG intensity reduction of fuels by 2030 (versus 2020 base line emissions)	14.5% GHG intensity reduction or 29% share of renewable energy in transportation (member states can choose; they can reduce the overall obligation if the cap on food and feed crops is lower than 7%)
Share of renewable energy in transportation in 2030	
Subtarget: Advanced biofuels and biogas (Annex IX-A)	Common target for advanced biofuels and RFNBO of at least 1% by 2025 and 5.5% by 2030. Minimum share of RFNBO: 1%%. Both advanced biofuels and RFNBOs can be double counted. Advanced biofuels and RFNBOs benefit from an additional multiplier of 1.2x and 1.5x, respectively, if used in aviation and marine sectors
Subtarget: RFNBO	
Cap on crop/feed-based biofuels and biogas	2020 share in energy in the transport sector +1%, up to max 7%
Cap on Annex IX-B biofuels and biogas	1.7% but member states can increase the limit
	(double counting allowed)
Definition of high indirect land-use change-risk biofuels: Maximum share of the average annual expansion of the global production area in high-carbon stocks	8%
Energy Share of Renewable Electricity multiple counting[1]	x4 for road, x1.5 for rail

Note: Multipliers only applicable to the accounting of energy shares (Art. 27.2). Accounting of GHG emission savings is never subject to multipliers (Art. 27.1).

3.2.2 EU Emissions Trading System (ETS) reform, CBAM and ETS II

Another key feature of the Fit for 55 package is the reform of the EU Emissions Trading System and the introduction of an ETS (ETS II) for buildings and road transport. The ETS is the European Union's "cap-and-trade" market-based system for carbon pricing and mandates entities covered by the ETS to surrender allowances for their greenhouse gas emissions. Each year, the cap on how many allowances is available on the market decreases, creating incentives for companies to reduce emissions. The original EU ETS was introduced in 2005 and the Fit for 55 package has reformed the system, with the reform being formally adopted in April 2023.

The reform of the ETS includes:

- A more ambitious emissions reduction goal of 62% by 2030 (when compared to 2005 levels), compared to the previous goal of a 43% reduction.
- A faster reduction of the cap on allowances. The previous target set a reduction of 2.2% per year between 2024 and 2030, while the new reform sets out a target of a 4.3% per year reduction between 2024-2027 and a 4.4% reduction per year between 2028-2030.
- The ETS will also extend to maritime transport; this is to be introduced gradually between 2024 and 2026.

- A gradual phasing out of free allowances for some sectors producing goods that are to be covered by a Carbon Border Adjustment Mechanism (CBAM). The phasing out of free allowances for those sectors will begin in 2026 and remain in place until 2034, when no more free allowances will be granted.

Alongside with the reforms to the EU ETS, the Fit for 55 policy package also introduces the CBAM. CBAM is to be introduced gradually in line with the phase-out of free allowances under the EU ETS and sets out that importers of certain goods into the EU will have to pay for the embedded carbon emissions generated in their production. By confirming that a cost has been paid for the embedded carbon emissions generated in the production of certain goods imported into the EU, the CBAM will ensure the carbon cost of imports is equivalent to the carbon cost of domestic production.

The CBAM has entered into force in its transitional phase as of October 1, 2023. It will initially apply to imports of certain goods and selected precursors whose production is carbon intensive and at significant risk of carbon leakage: cement, iron and steel, aluminium, fertilizers, electricity, and hydrogen. For this study, it is assumed that free allowances for fuels production will be phased out by 2035, and that full ETS costs will be applied to fuels produced in the EU from this date. Correspondingly, it is assumed that fuel imports will be subject to CBAM from this date. It is assumed that no recovery of ETS costs will be allowed for fuels sold outside of the EU.

As well as the reform to the existing EU ETS, a new EU ETS is to be introduced for buildings and road transport, called the EU ETS II. It will also cover additional sectors not covered by the existing EU ETS, which is mainly small industry emitters. The ETS II is separate from the existing EU ETS which covered emissions from electricity and heat generation, industrial production, maritime transport and commercial aviation.

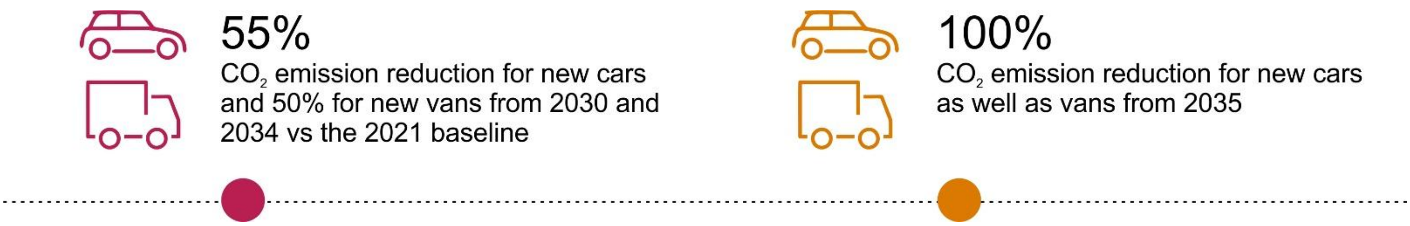
ETS II sets a target to achieve a 43% emission reduction by 2030 compared to 2005 emissions for the sectors covered by ETS II.

The ETS II is set to launch in 2027 but can be delayed by one year in the event of exceptionally high energy prices. The system covers upstream emissions and so the regulations impact fuel suppliers. Allowances for fuel suppliers will be available exclusively through an auctioning system (i.e., no free allowances will be distributed), and the, price of allowances will be subject to stabilization mechanisms. It is expected that costs for ETS II will be passed on to end-users.

3.2.3 CO_2 emissions standards for cars and vans

To help cutting carbon emissions in the transport sector, the Fit for 55 policy package has set out stricter CO_2 emission performances standards for new cars and vans. The revised Regulation on CO_2 emission standards adopted on 19 April 2023 sets out EU fleet-wide CO_2 emission targets defined as a percentage reduction from a 2021 baseline, notably:

Figure 3.4 – Road emission reduction targets



With this revised Regulation, the EU became the first major region worldwide to introduce a fleet CO_2 tailpipe emission target of 0 g/km for all cars and vans newly registered from 2035 onwards. Note in the Max Electron scenario these regulations are met but in the More Molecule scenario we have allowed sales of PHEV (plug in hybrid electric vehicles) sales post 2035 for passenger cars and light commercial vehicles. Beyond the EU revised regulation, following consultation with stakeholders, the Commission will make a proposal for registering after 2035 vehicles running exclusively on CO_2 neutral fuels.

3.2.4 ReFuelEU Aviation and FuelEU Maritime

The ReFuelEU Aviation initiative was one of the proposals within the Fit for 55 package which aims to ensure sustainable air transport. The proposed regulation obliges fuel suppliers to distribute sustainable aviation fuels (SAF), with an increasing share of SAF (including synthetic aviation fuels, or e-fuels) over time, in order to increase the uptake of SAF by airlines and thereby reduce GHG emissions from aviation. It also requires EU airports to have the necessary infrastructure to deliver, store, and refuel with sustainable aviation fuel.

ReFuelEU Aviation proposes setting the minimum share of SAF supplied at each EU airport at 2% in 2025 and 6% by 2030, increasing to 20% by 2035, 34% by 2040, 42% by 2045, and 70% by 2050. Within the SAF requirement, a sub-obligation mandates e-fuels that increases up to 35% by 2050.

The FuelEU maritime initiative is also a part of the ‘Fit for 55’ package with the prime goal of increasing the use of renewable and low-carbon fuels in the shipping sector as well as reducing greenhouse gas emissions. It introduces GHG intensity reduction targets for shipping with the GHG intensity of fuels used in ships traveling in the EU to be cut by 80% by 2050.

The targets cover CO2, methane and nitrous oxide emissions and apply to ships over 5,000 gross tonnage (GT) traveling between EU ports and to 50% of the fuel used “on voyages where the departure or arrival port is outside of the EU or in EU outermost regions.” The cuts will be calculated against a 2020 baseline of 91.16 grams of CO2 per megajoule (MJ). GHG cuts from RFNBOS (incl. renewable hydrogen and green ammonia) will be rewarded with a factor of 2 until the end of 2033.

Furthermore, the European Commission will review the rules by 2028 and can propose to extend the targets to smaller ships or to increase the coverage of GHG cuts for journeys outside the EU beyond 50%. The Commission could set a 2% RFNBOs target from 2034 if RFNBOs account for less than 1% of the shipping fuel mix in 2031.

Figure 3.5 – ReFuelEU Aviation and FuelEU Maritime Targets to 2050

* eSAF: 2030-31: 0.7% min each year for 1.2% average over period, same mechanism in 2032-33 with yearly min. of 1.2% and average 2%
**Fixed 2% in 2034

3.2.5 The New EU Forest Strategy for 2030 and Regulation on Land Use, Land Use Change and Forestry (LULUCF)

The New EU Forest Strategy for 2030, published in July 2021 and replacing the EU Forest Strategy adopted in 2013, lays out the strategy to improve the quantity and quality of EU forests to improve carbon removals by natural sinks. The land forestry sector in the EU is a source of carbon removal due to trees and plants absorbing CO2 from the atmosphere.

The improvement of the forests as natural carbon sinks is central to meeting the greenhouse gas emissions and carbon removals targets set by the Regulation on Land Use, Land Use Change and Forestry (LULUCF).

LULUCF, originally launched in 2018, sets the guide for emission reduction and carbon removals in the LULUCF sector. The original LULUCF policy set out a 2030 target of 225 million tons of CO2 equivalent to be removed from the atmosphere. The Fit for 55 package has reformed the LULUCF and has set a new 2030 target for carbon removals of 310 million tons of CO2 equivalent.

This new 2030 target is part of a two-phase approach to the revised regulation for LULUCF:

Phase 1: From 2021 to 2025, the regulation stays close to the original LULUCF regulation where each Member State ensures that accounted emissions from land use are compensated by an equivalent amount of accounted carbon removals.

Phase 2: From 2026 to 2030, the EU-wide target of -310 Mt CO2 equivalent of net removals by 2030 is introduced and the phase enlarges the territorial scope to cover all managed land.

3.3 REPowerEU

The REPowerEU plan, issued on 18 May 2022, was the EU's response to the global energy market disruption caused by Russia's invasion of Ukraine. The REPowerEU plan outlines how Europe can reduce its dependency on Russian fossil fuel and pursue an accelerated pace of renewable additions, reductions in energy demand and diversification of energy supplies. The policy initiative contains a range of ambitious proposals that build on the Fit for 55 package.

One of the key implications of the REPowerEU package was a target for a significant growth in renewable hydrogen use by 2030. The subtarget for RFNBOs, which also includes hydrogen and its derivatives, would see renewable hydrogen use increasing from 50% of industrial hydrogen to 78%, and from 2.6% of transport fuels to 5.7%, both by 2030.

The original target for renewable hydrogen use implied 5.6 million metric tonnes (MMt) of renewable hydrogen by 2030; the new target sets a plan for 10 million tonnes of renewable hydrogen to be produced within the European Union and 10 MMt to be imported by 2030, in line with the goals of REPowerEU.

3.4 UK Renewable Transport Fuel Obligation (RTFO)

The UK Renewable Transport Fuel Obligation Order (RTFO) regulates renewable fuels used for transport and covers biofuels, RFNBOs and some advanced biofuels. RTFO aids in decarbonizing transportation segment by supporting production as well as use of renewable fuels.

Operators supplying more than 450,000 liters per year of transport fuels (gasoline, diesel, gasoil, the non-renewable portion of any partially renewable fuel) to relevant transport modes are subject to a renewable fuels' obligation, which comprises the "main obligation" and the "development fuel target". The relevant transport modes are road vehicles, non-road transport, aviation and maritime (maritime is only covered by the RTFO Order when the fuel used is a RFNBO).

For a fuel to qualify as a development fuel the criteria are:

- Made from sustainable wastes or residues which the Administrator considers as eligible for double RTFCs, apart from segregated oils and fats such as used cooking oil and tallow (advanced biofuel)
- A RFNBO
- In addition, a development fuel must be one of the following types:
  - Hydrogen
  - Aviation fuel (avtur or avgas)
  - Substitute natural gas - renewable methane produced from gasification or pyrolysis
  - A fuel that can be blended such that the final blend has a renewable fraction of at least 25% whilst still meeting BS EN: 228 (for gasoline, as revised or reissued from time to time) or BS EN: 590 (for diesel, as revised or reissued from time to time)

The development fuel target takes into account:

- The fuel type, production pathway and feedstock
- Suppliers need to meet the developmental fuel target with 'development fuel' RTFCs, issued to qualifying development fuels. RTFCs can be carried forward to the next year to meet up to 25% of a supplier's obligation
- The target level is set each year. Development fuels are incentivized by awarding double the RTFCs per liter or kilogram supplied. This means that they may be double-counted under the RTFO, so that the actual equivalent volume of development fuel supplied will be half of the fuel target volume

Table 3.2: Targets are per RTFO compliance guidance 2023'

Obligation period (1 Jan - 31 Dec)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032 onwards
Main obligation %	12.6	13.08	13.56	14.05	14.55	15.06	15.57	16.08	16.61	17.14	17.68
Development fuel target %	0.91	1.14	1.38	1.62	1.86	2.11	2.36	2.61	2.87	3.13	3.39
Total obligation %	13.51	14.22	14.94	15.67	16.42	17.17	17.92	18.69	19.47	20.27	21.07

Note: the targets are expressed as % volume of FOSSIL fuel supplied.
Source: S&P Commodity Insights. (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate.)

Sustainable biofuel suppliers gain Renewable Transport Fuel Certificates (RTFCs) once they meet specified sustainability criteria and these RTFCs can then be traded in the open market.

While specific UK regulations or proposed regulations aimed at reducing CO2 emissions or meeting net zero by 2050 may differ from EU regulations, for the purpose of this study the UK has been aligned with the individual scenario assumptions, which are based on meeting EU regulations, mandates and targets.

3.5 References

For this legislation summary S&P Global used the sources listed below.

CBAM

https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

Energy Taxation Directive

https://www.europarl.europa.eu/legislative-train/spotlight-JD22/file-revision-of-the-energy-taxation-directive

Energy Efficiency Directive

https://energy.ec.europa.eu/topics/energy-efficiency/energy-efficiency-targets-directive-and-rules/energy-efficiency-directive_en

ETS

https://www.consilium.europa.eu/en/infographics/fit-for-55-eu-emissions-trading-system/

https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/ets-2-buildings-road-transport-and-additional-sectors_en

European Climate Law

https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32021R1119

https://climate.ec.europa.eu/eu-action/european-climate-law_en#:~:text=The%20European%20Climate%20Law%20writes,2030%2C%20compared%20to%201990%20levels.

Fit for 55:

https://www.consilium.europa.eu/en/policies/green-deal/timeline-european-green-deal-and-fit-for-55/

https://www.consilium.europa.eu/en/press/press-releases/2023/03/10/council-and-parliament-strike-deal-on-energy-efficiency-directive/

https://www.consilium.europa.eu/en/press/press-releases/2023/10/09/renewable-energy-council-adopts-new-rules/

https://www.consilium.europa.eu/en/infographics/fit-for-55-how-the-eu-plans-to-boost-renewable-energy/

FuelEU Maritime

https://www.consilium.europa.eu/en/press/press-releases/2023/07/25/fueleu-maritime-initiative-council-adopts-new-law-to-decarbonise-the-maritime-sector/

REDII

https://joint-research-centre.ec.europa.eu/welcome-jec-website/reference-regulatory-framework/renewable-energy-recast-2030-red-ii_en

ReFuelEU Aviation

https://www.europarl.europa.eu/RegData/etudes/BRIE/2022/698900/EPRS_BRI(2022)698900_EN.pdf

https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-refueleu-aviation

https://www.consilium.europa.eu/en/press/press-releases/2023/10/09/refueleu-aviation-initiative-council-adopts-new-law-to-decarbonise-the-aviation-sector/

REPowerEU

https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en

RTFO

https://www.gov.uk/guidance/renewable-transport-fuels-obligation

4 Scenarios

This section provides a summary of S&P Global's scenario modelling methodology and assumptions, as well as the high-level outputs of the two bespoke scenarios that were created for this study – **Max Electron** and **More Molecule**.

S&P Global has a dedicated scenario modelling team, providing alternative future scenarios for clients via our Energy and Climate Scenario service. These are typically used by clients for creating and testing strategy.

S&P Global has five different pathways out to 2050, illustrating the pace of change in long-term global energy supply, demand, and trade, based on current views and assumptions about economic growth, markets, policy, consumer behavior, and technology. These include three bottom-up plausible energy-integrated forecasts to 2050 and two net-zero cases that are constructed backwards starting with a predetermined end point of global net-zero emissions by 2050.

The three bottom-up scenarios are called **Inflections** (our base case), **Green Rules** and **Discord**. Green Rules is essentially our current view of the fastest plausible energy transition, but it is not net zero globally, and results in a global temperature rise of +1.7°C by 2100. In the case of Europe, though, Green Rules comes very close to net-zero emission by 2050.

For this study, the Green Rules scenario was used as the starting point, and this was adjusted to create two bespoke scenarios:

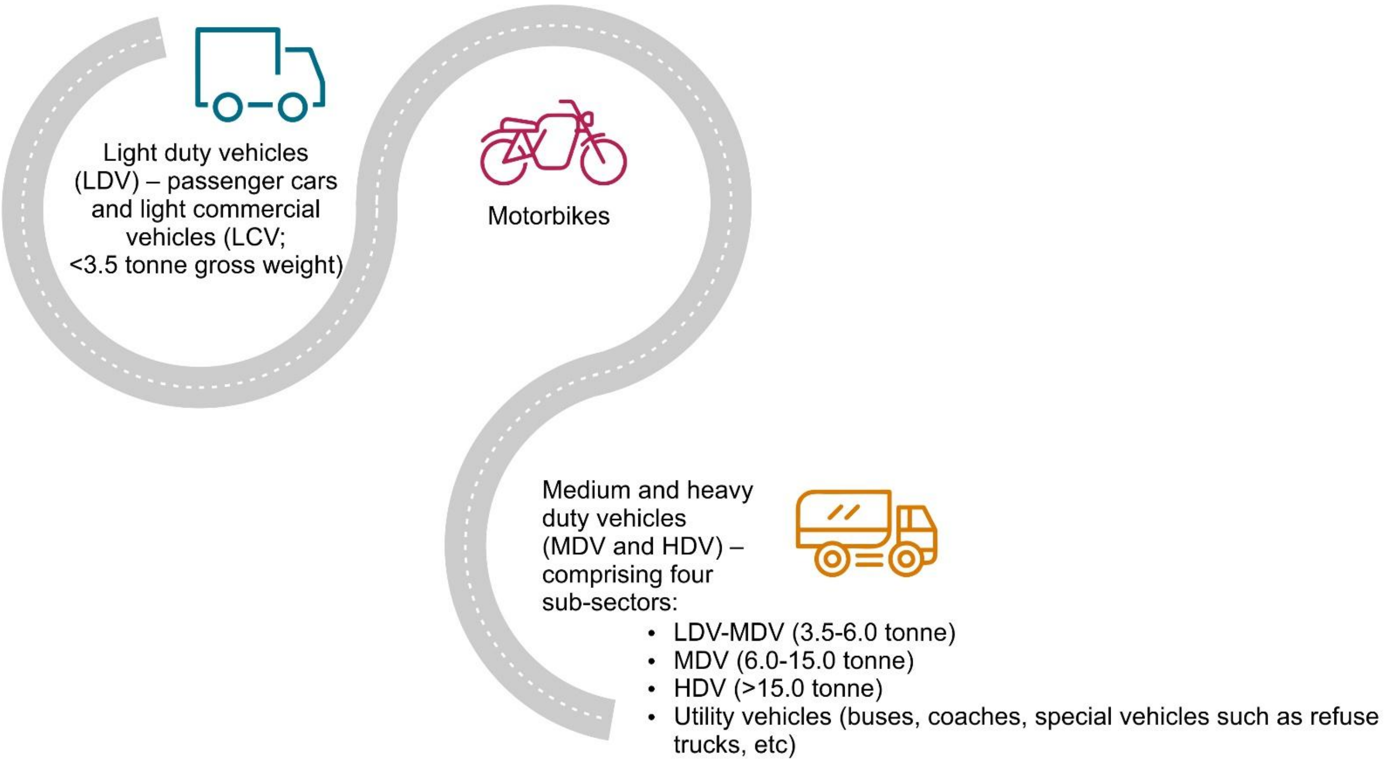
Max Electron	This scenario achieves net zero by 2050 for the EU+ set of countries, meeting the requirements of Fit for 55, RefuelEU Aviation and FuelEU Maritime, achieved via an accelerated rate of electrification across various modes of transportation, more aggressive than Green Rules. This scenario relies on the widespread adoption of electric vehicles (LDV and limited HDV), transforming the landscape of personal and commercial transportation and considers electrification possibilities in the aviation and marine sectors. The Max Electron Scenario represents a comprehensive and innovative approach to reducing carbon emissions, fostering clean energy solutions, and ushering in a new era of electrified mobility.
More Molecule	This scenario is based on meeting net zero by 2050 for the EU+ set of countries, meeting the requirements of ETS, RefuelEU Aviation and FuelEU Maritime. This is achieved via an accelerated substitution of traditional fuels by low carbon fuels combined with a high degree of electrification, although not meeting the requirements of vehicle standards in Fit-for 55. These low carbon fuels encompass hydrogen and its derivatives such as synthetic fuels, ammonia, e-methanol etc., as well as advanced biofuels. By pivoting towards these innovative and eco-friendly alternatives, the More Molecule Scenario seeks to achieve the EU targets of emissions reduction but with more low carbon fuels, particularly biofuels compared to the Max Electron scenario. It allows for continued sales of ICE vehicles post 2035.

While this study considers all relevant European legislation concerning the reduction of greenhouse gas emissions (as described in Section 3), the evaluation of the impact of potential regulatory changes such as changes in fuel specifications or environmental requirements are out of scope.

4.1 Road Transport Modelling Methodology

The road transport sector is broken down into three main groupings:

Figure 4.1 – Road transport groupings



Each of these are modelled as time series stock models, with some additional econometric relationships. The road passenger model is a stock model based on the sales of new vehicles and the retirement of existing vehicles. The road freight models include econometric relationships between tonne-kilometers transported and industrial output.

Each of the models includes alternative propulsion technologies, typically:

- Gasoline
- Diesel
- Full Hybrids: Gasoline, Diesel, Natural Gas (i.e. not plug-in)
- Plug-in Hybrid Electric Vehicles: Gasoline, Diesel, Natural Gas
- Pure Battery Electric Vehicles
- Natural Gas Vehicles
- LPG Vehicles
- Hydrogen Fuel Cell Vehicles

Specific inputs to the model such as individual vehicle type scrappage rate, fuel efficiency, and likely satiety level are derived from S&P Global proprietary automotive fleet databases and forecasts.

Each vehicle technology is modelled in terms of new registrations, scrappage and the total on-road fleet, (vehicle parc). The modelling is based on a stock model with the total vehicle parc divided between new and retained vehicles and the various fuel types. The vehicles are then multiplied by the annual average distance driven and the average fuel efficiency for new and retained cars to determine the fuel consumption.

GDP per capita provides the income indicator driving the growth in the total vehicle parc. New vehicle sales/registrations are the difference between the total vehicle parc and scrapped vehicles, with the scrappage rate an exogenous input. The type of new vehicles entering the market is a function of the relative economics of the different power trains as well as policy measures. Running costs are a function of the vehicle cost (including any subsidies), insurance and other charges, fuel costs and fuel efficiency. Other policy restrictions are included, such as banning certain types of vehicles.

The fuel efficiency of new vehicles is an exogenous input, while the average distance driven (road km) is a function of the cost of fuel and individual wealth. Combining the parc data with the fuel efficiency and distance driven provides the overall fuel consumption by power train. This is broken down into the different fuel inputs required.

The demand for passenger vehicles can be described by a reciprocal model. There is a critical level or threshold level of income below which vehicles are not affordable. There is an upper boundary or satiety level beyond which demand will not grow (even millionaires do not usually own more than 2 or 3 vehicles at a time). The satiety level has been estimated using cross-country data but can be used as a policy variable to adjust the level of market saturation.

Changes in the cost of vehicle ownership can shift the threshold and demand curve further along the disposable income per capita axis. Once the threshold level has been determined, then the reciprocal model calculates the overall vehicle parc.

The equation works well for relatively high-income groups, where they approach the satiety level, i.e. in the section of the curve above where its differentiation is greatest; the point where the slope on the curve is changing the fastest as the income per capita increases. Below this level a form of logistic curve is the best fit. The vehicle per capita equation is modified to take this into account.

4.1.1 Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km.

4.1.2 Annual cost of driving per new vehicle

The annual cost of driving a new vehicle will depend on fuel prices, kilometers travelled, efficiency of the new vehicle, plus any annual fees imposed as policy levers to encourage/discourage driving a specific type of vehicle. The annual driving costs are unitized by dividing it by the average distance driven to give a cost per 1000 km. The total driving cost is the sum of the vehicle cost, plus the annual fuel costs and the annual taxes.

4.1.3 Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fueling stations/points and conceptually how easy it is to maintain. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing gasoline and diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

4.1.4 Annual distance driven (road km)

The annual distance driven per vehicle can either be an internally calculated value based on the retail fuel price and GDP per capita or it can be an exogenous variable defined by the model user. An advantage to having this variable as an exogenous input is that it enables the user to test out the sensitivity of the fuel demand to this key input.

Going forward, new policies created to impact vehicle miles travelled (VMT), such as congestion charging, limit parking, and vehicle sharing, would need to be incorporated into the model.

The starting point for electric vehicles is for lower milage than for internal combustion vehicles. Electric passenger vehicles are assumed to be able to drive 10,000 km per year (40 km per day for 5 days a week for 52 weeks in the year), while electric light commercial vehicles are assumed to cover 20,000 km per year.

4.1.5 Road Fuel Consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

4.1.6 Inputs and Outputs

The key inputs to each model typically include:

- Real GDP per capita and average consumer expenditure
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated road tax and insurance
- The retirement profile of the existing fleet of vehicles
- Fuel efficiency of new vehicles
- Policy options to favour certain technologies and change the average road km driven

The key outputs to each model typically include:

- Fleet of vehicles by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emissions

4.2 Macro and Demographic Model

The existing macroeconomic and demographic sub-model contains SPGCI base case outlook and allows the user to run sensitivities to changes in global and national GDP, as well as the impact of global oil price changes.

4.2.1 Inputs and Outputs

The key inputs are:

- Base macro and demographic data assumptions
- Urbanisation rate
- Oil and carbon price assumptions

The key outputs for the road transport model are:

- GDP (real and nominal)
- Consumer expenditure (real and nominal)
- Industrial output
- Population – total and urban
- US dollar exchange rate
- Inflation – GDP deflator
- Interest rates

4.2.2 Retail fuel prices

SPGCI energy model has a pricing sub-model to convert international wholesale prices to national markets' retail prices. This is an important part of the model to provide the inputs to running costs as well as behavioural drivers such as road-km driven.

The model enables users to input the global oil price (Brent crude oil price) and a number of other international benchmark prices (ARA coal prices, natural gas prices, carbon prices etc.) and these flow through to the end-use retail prices in each country, reflecting the historic relationship between the international prices and national retail prices.

4.2.3 International benchmark prices

International benchmark prices are largely exogenously determined. However, for the scenarios it is important that all benchmark prices for a certain type of fuel are linked together. For example, there are four main crude prices in the model: Dated Brent, WTI, Dubai and Urals. These marker crudes are price setters in different locations, but there is generally little difference between the crudes.

The base-case difference between the crudes is maintained for the scenarios, with the ability to adjust the difference exogenously. To achieve this, a single marker crude is used as the main reference, in this case Dated Brent, from which the other crude prices are determined. A similar approach is adopted with coal and carbon. These benchmark prices are then fed into the country-specific price calculations.

4.2.4 Crude Oil Prices

In the model there are four market crude oil prices:

- Dated Brent
- West Texas Intermediate (WTI)
- Dubai
- Urals

Dated Brent is the main marker crude and is an exogenous input to the model, with the values coming from S&P Global's Green Rules scenario. The other crudes are derived as simple differentials to Dated Brent.

4.2.5 Oil Product Prices

There are seven petroleum products:

- Naphtha
- Gasoline
- LPG
- Jet Fuel
- Gasoil
- Low Sulphur Fuel Oil (LSFO)
- High Sulphur Fuel Oil (HSFO)

Diesel and other derivatives of gasoil, such as marine gasoil are grouped and classed as "gasoil", this follows IEA historical data reporting, separate analysis would not be expected to change high-level conclusions.

There are four main markets and their associated crude oil:

- US Gulf Coast (GCO) - WTI
- Singapore (SGP) - Dubai
- NW Europe (NWE) - Brent
- Mediterranean (MED) - Brent

Oil prices are based on the underlying crude oil prices (the pass through of crude price changes to oil product prices, which is estimated from a linear regression) and changes in the crack margin due to upgrading investments (i.e. investment in additional cracking capacity that impacts the international benchmark prices).

4.2.6 Natural Gas Prices

International benchmark gas prices tend to be endogenous to the model, either linked to oil product prices or the marginal cost of supply. In general, natural gas prices are either determined by one or more of the following options:

- Oil-indexed prices – gas prices change with changes to spot oil product prices;
- Regulated prices – gas prices are determined by the government
- Spot prices – gas prices are linked to the marginal cost of supply

4.2.7 Carbon Prices

There are five reference carbon prices considered:

- European Emission Trading Scheme (ETS) – EU Allowances (EUA)
- US trading system, e.g. California ETS/LCFS
- Japanese trading system
- Australia-New Zealand trading system
- South Korea – trading system

4.2.8 End-use retail prices

The various international benchmark prices are allocated to each country as a reference series. The data is converted from US$ into the local currency unit. Distribution costs and margins are added to the import price based on the historical relationship between the pre-tax prices and the international prices.

The appropriate taxes are added to the pre-tax values to arrive at the retail price. To this can be added the implied carbon price, if there is such a price and it applies to the specific sector. The intension is that the retail plus the carbon cost will reflect the actual cost faced by consumers and will be part of the price sensitivity of consumers.

- Oil prices: Import price + transport & margin + taxes + carbon price
- Natural gas prices: Import price + transport & margin + taxes + carbon price
- Electricity prices: Wholesale price + transport & margin + taxes
- Carbon price is not directly applied to the cost of the fuel but is an implied cost that we add so that it influences the substitution and efficiency choices. Assumptions need to be made regarding any free allocation and whether this is passed through to consumers or whether the full opportunity cost is assumed. Additionally, assumptions need to be made concerning sectors covered by the cost – does it apply to industry and power only or transport and domestic as well? These options are exogenous inputs to the model.

4.2.9 Inputs and Outputs

The key inputs are:

- International benchmark marker prices
- International price differentials

- Exchange rates
- Deflators
- Excise taxes and VAT

The key outputs are:
- Retail prices for road transport fuels
- Retail prices plus implied carbon price
- Road transport fuels retail prices cover:
    - Gasoline
    - Diesel
    - LPG
    - Natural Gas
    - Electricity

4.3 Data Sources

Car parc data from IHS Markit Automotive service, based on S&P Global POLK data.

Road transport energy consumption from the IEA's global annual energy statistics. Breakdown into road transport segments based on S&P Global estimates. Road transport pricing from S&P Global data sources, including S&P Global OPUS.

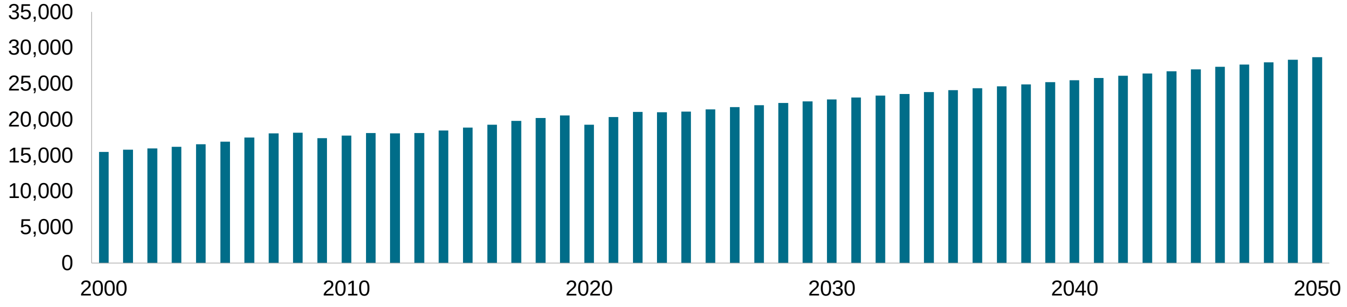
4.4 Scenario Activity Outlooks

S&P Global's scenario models include various assumptions, macro-economic indicators and activity forecasts. These have been generated by a combination of analysis and modelling and are detailed in Appendix A, split by the different transport and consumption sectors. In this section we show some of the key economic and transport activity outlooks used in the scenarios.

4.4.1 Macro Economic Forecasts for EU+

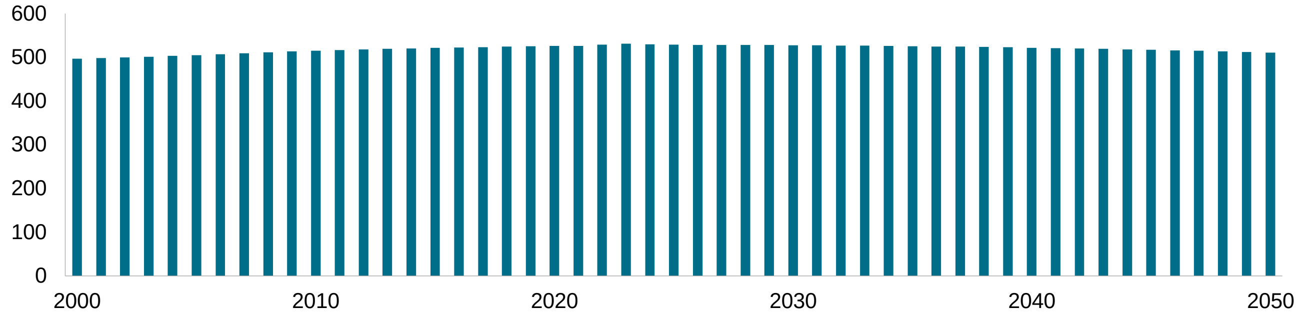
S&P Global forecasts EU+ GDP growth to average around 1% per annum, combined with slight total population decline and industrial sector output growth to average 1.2% per annum in the period 2024-50, as shown in Figures 4.2-4.4.

Figure 4.2 – EU+ GDP outlook (constant 2022 billion US$)



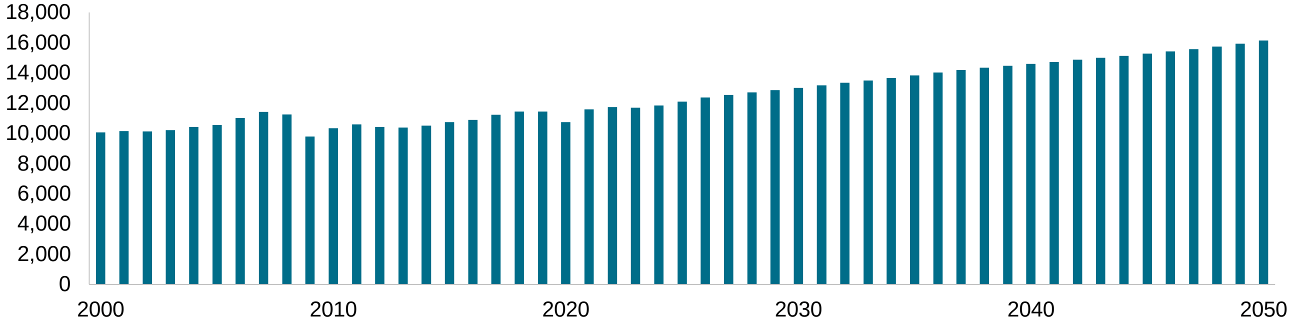
Source: S&P Global Commodity Insights.

Figure 4.3 – EU+ Population Outlook (million)



Source: S&P Global Commodity Insights.

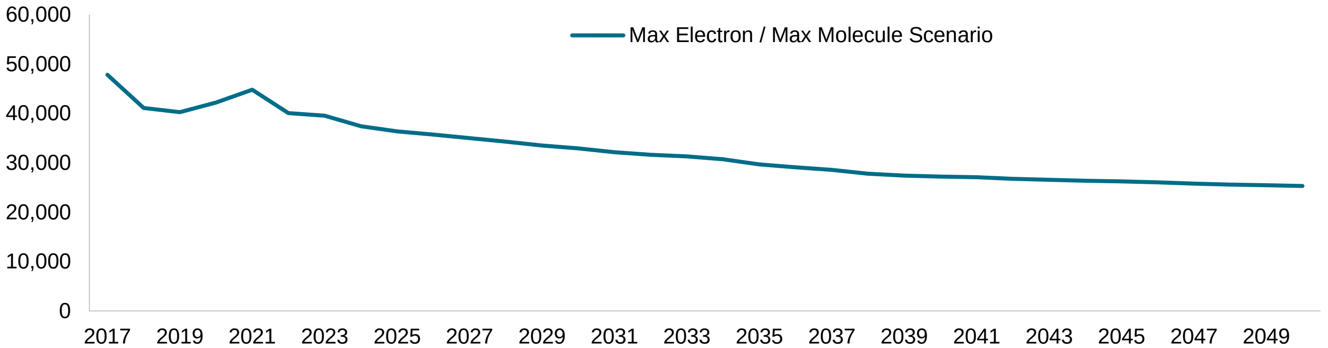
Figure 4.4 – EU+ Industrial Sector Output (real billion $US)



Source: S&P Global Commodity Insights.

Although Industrial Sector output increases, within the Petrochemical Industry, production of virgin plastics under the Green Rules scenario is expected to fall.

Figure 4.5 – EU+ Naphtha Demand, thousand tonnes per annum



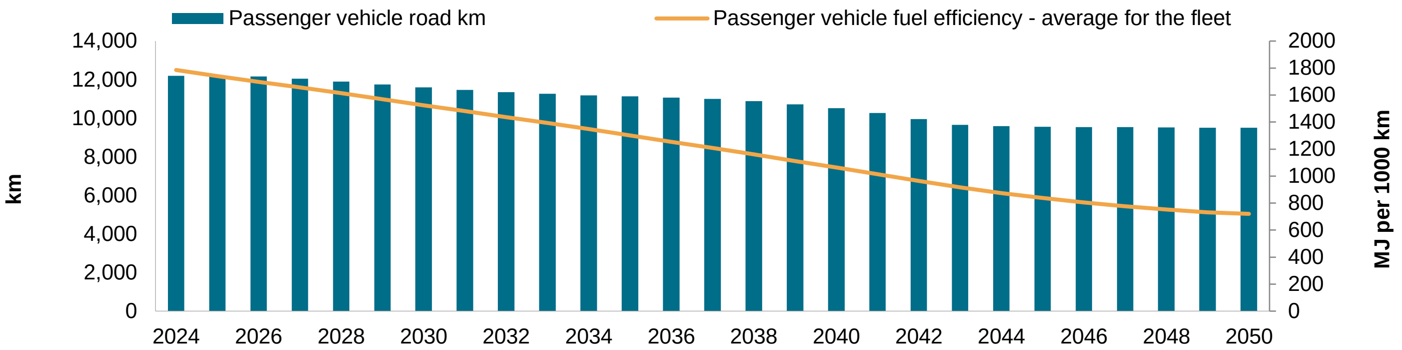
Source: S&P Global Commodity Insights.

This is driven primarily by increased physical recycling of plastics, increased chemical recycling of plastics, and downward pressure on total plastic demand caused by either charges for, or bans on the single-use of plastic items. As a result, petrochemical feedstock (naphtha) demand shows a different trend to overall Industrial Sector output.

4.4.2 Road Transport Activity Forecasts for EU+

Figures 4.6-4.10 show the road activity forecasts split by vehicle type.

Figure 4.6 – EU+ Passenger Vehicle Road kms and Fuel Efficiency



Source: S&P Global Commodity Insights.
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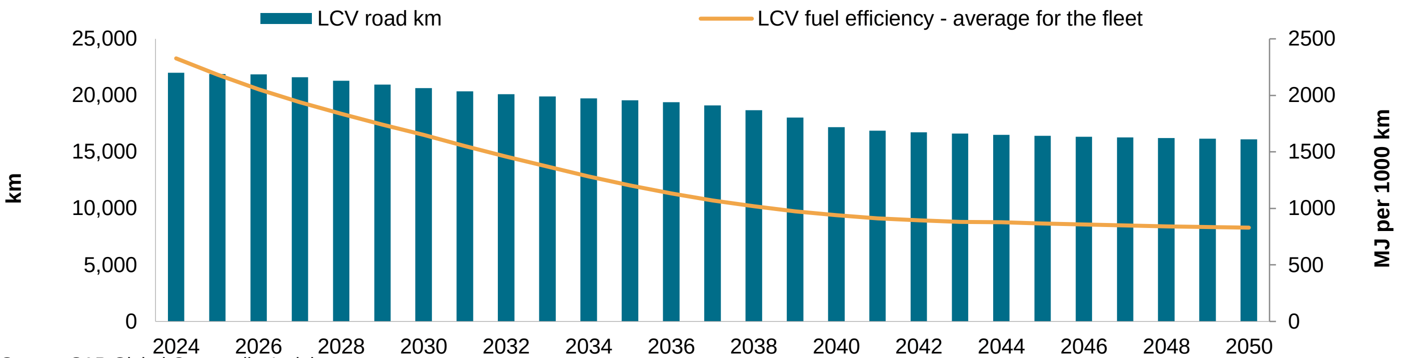
Figure 4.7 – Light Commercial Vehicles (LCV) Road kms and Fuel Efficiency



Source: S&P Global Commodity Insights.
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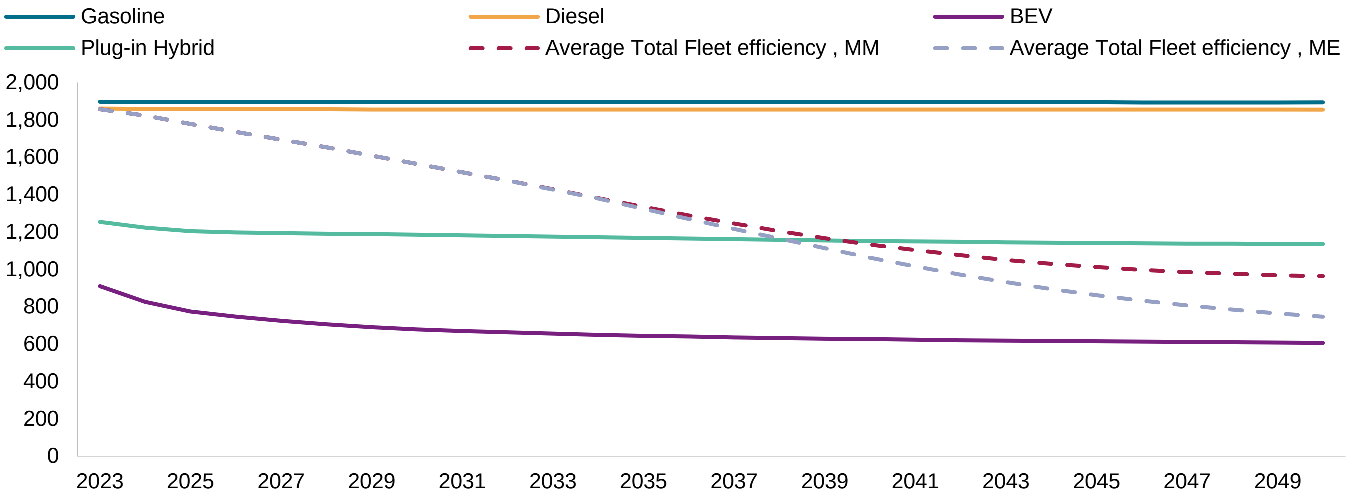
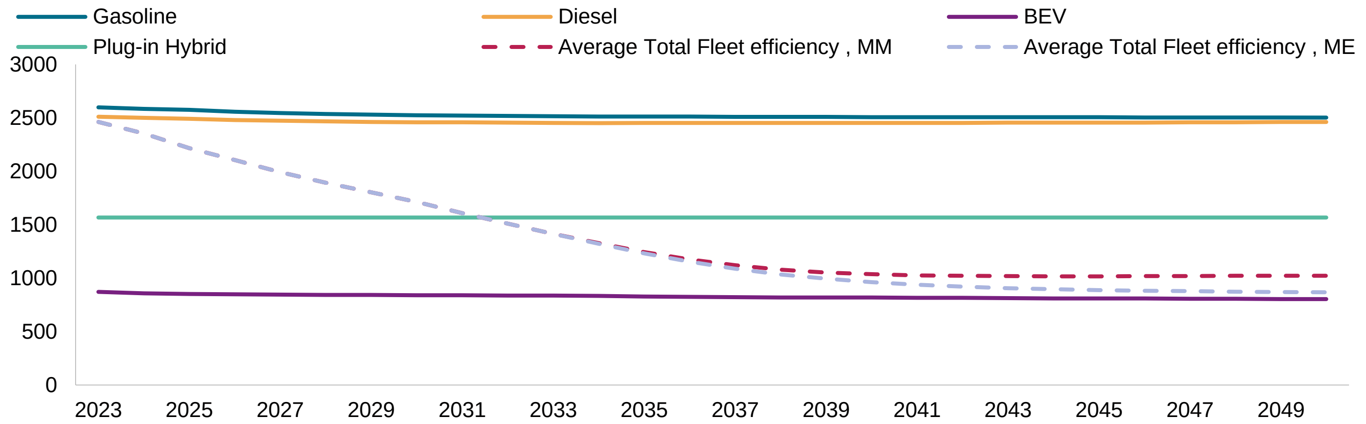
Figure 4.8 – EU+ Passenger Vehicle Efficiency (MJ/1000 km)



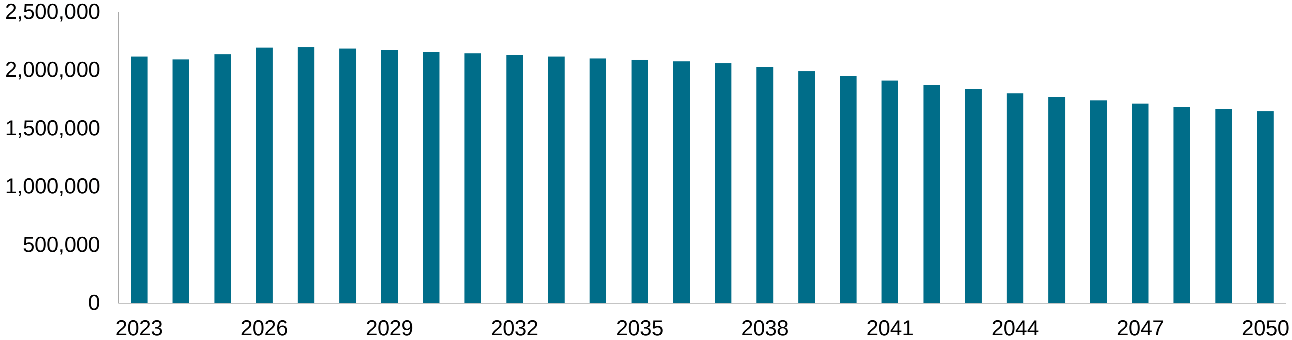
Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Figure 4.9 – EU+ LCV Efficiency (MJ/1000 km)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Figure 4.10 – EU+ Heavy Road Transport Freight (million tonne kms)

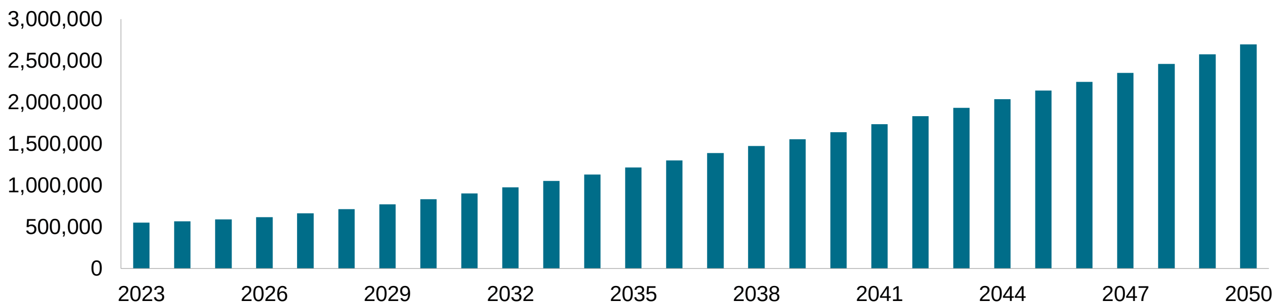


Source: S&P Global Commodity Insights.

Note EU+ New Road Vehicle Sales, Fleet Population and Vehicle Efficiencies are detailed in Appendix A

4.4.3 Rail Freight Activity Forecasts for EU+

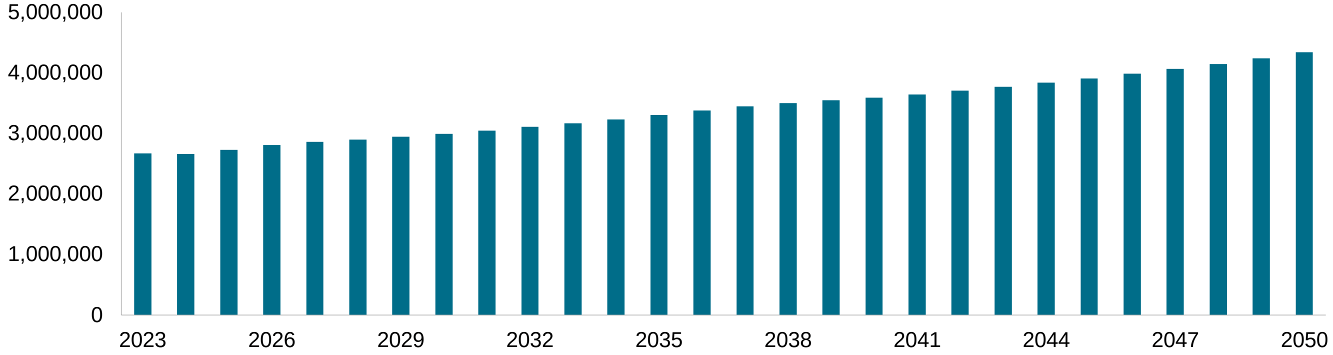
Figure 4.11 – EU+ Total Rail Freight Outlook (million tonne km)



Source: S&P Global Commodity Insights.

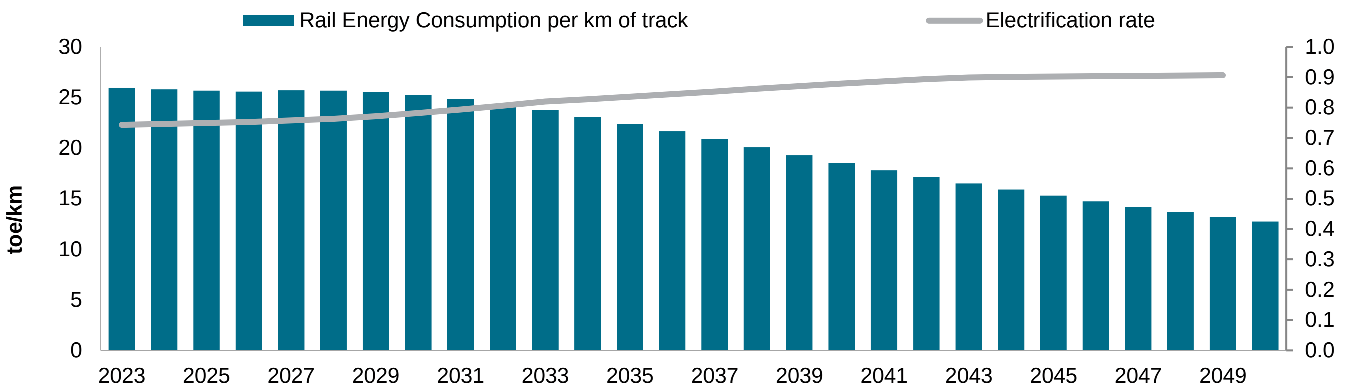
S&P Global expects growth in rail freight to average 6% per annum in the period 2024-50. This might seem high but when combined with our expected decline in road freight over the same period, S&P Global's outlook for total land based freight is an average growth of just 2% per year, shown in Figure 4.12. The rail network includes mass transit in urban areas such as tramways and there are schemes looking to expand these services, as well as expanding regional networks with high-speed lines. Structural and operational improvements to solve congestion issues on the rail network and improved cross-border coordination will need to be implemented to allow for this significant increase in rail freight.

Figure 4.12 – EU+ Total Land Based Freight (Road + Rail) Outlook (million tonne km)



Source: S&P Global Commodity Insights.

Figure 4.13 – EU+ Rail Energy Efficiency and Electrification Outlook

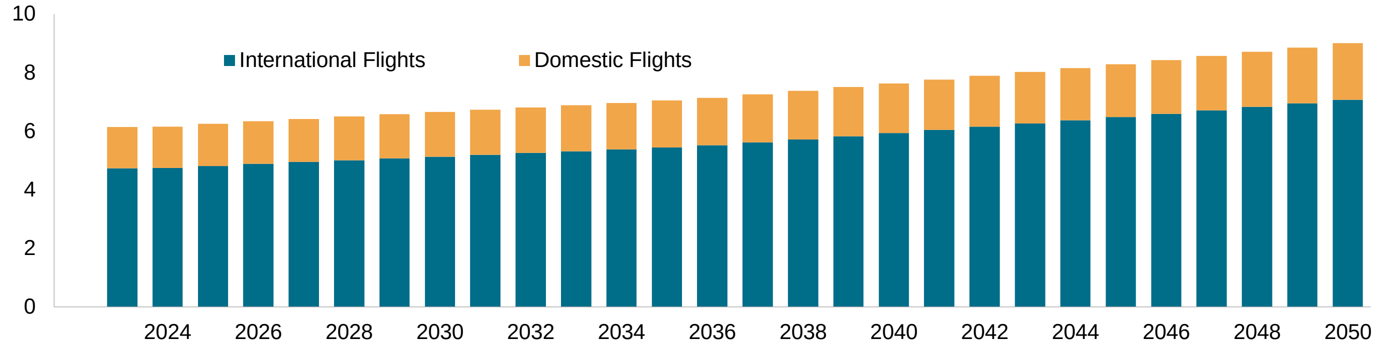


Source: S&P Global Commodity Insights.

4.4.4 Aviation and Maritime Activity Forecasts for EU+

S&P Global expects total aviation activity growth to average 1.4% per year in the period 2024-50 as shown in Figure 4.14.

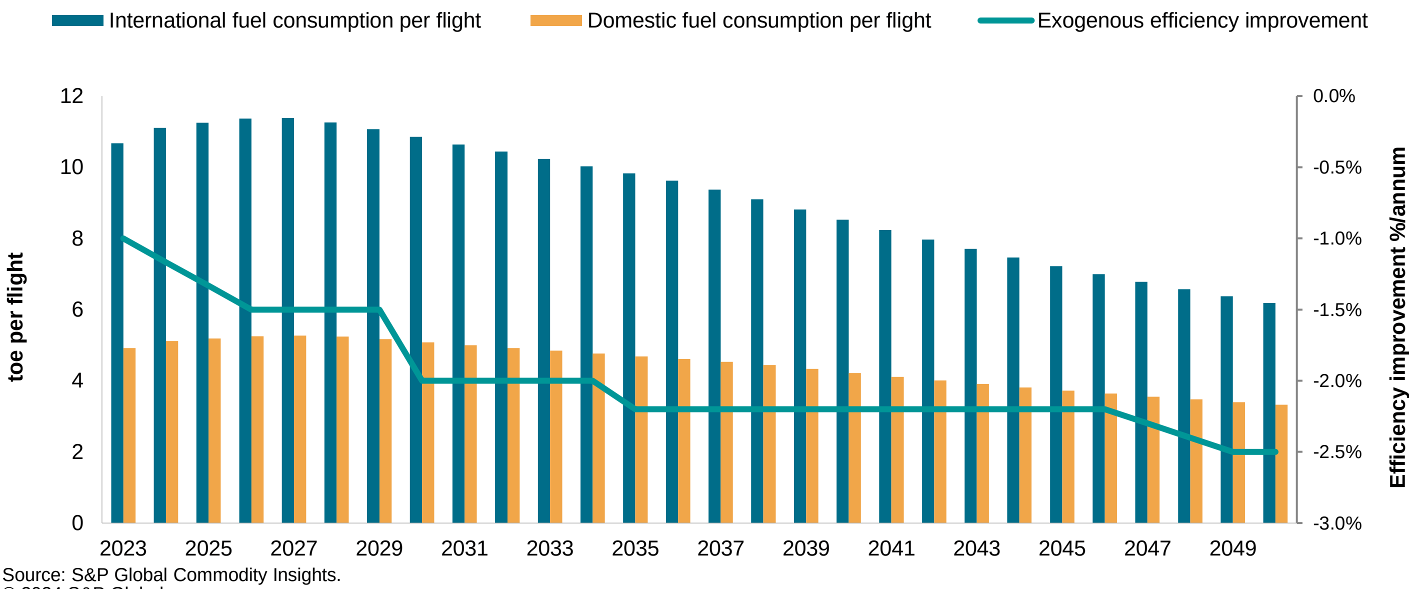
Figure 4.14 – Domestic and International Aviation Activity Outlook (million flights)



Source: S&P Global Commodity Insights.

In the short-term increased demand for both business and leisure travel post Covid, with airlines looking to increase utilization rates to improve profitability, and delays in delivery of new aircraft all contribute to an increase in fuel consumption per flight. Longer term a combination of improved aircraft design and improving engine efficiency, combined with the natural turnover as new aircraft replace older aircraft in the commercial aviation fleet are expected to deliver a reduction in aviation fuel consumption per flight. This efficiency improvement is expected to accelerate driven by both decarbonization and cost-reduction pressure.

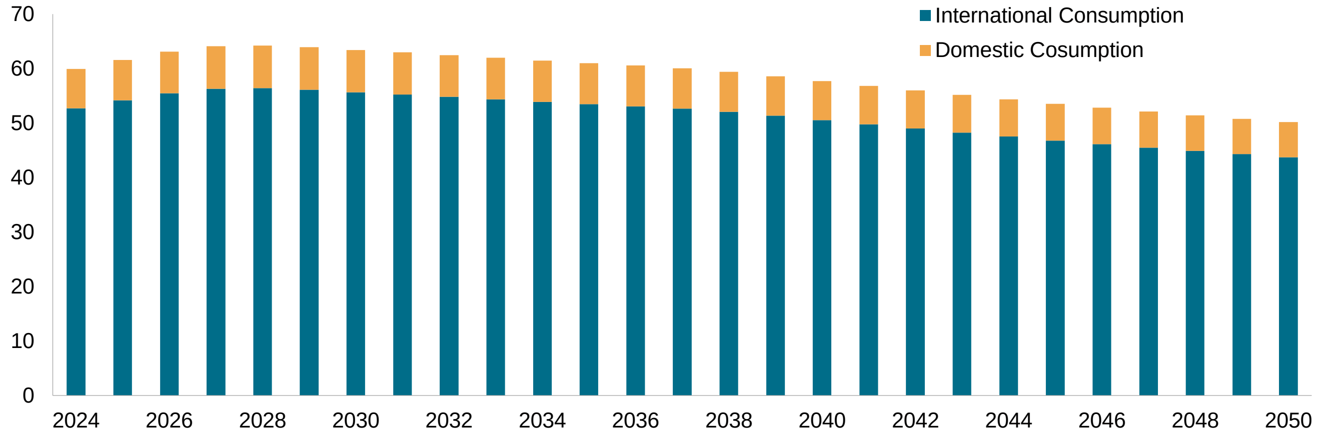
Figure 4.15 – Aviation Efficiency Outlook



Source: S&P Global Commodity Insights.

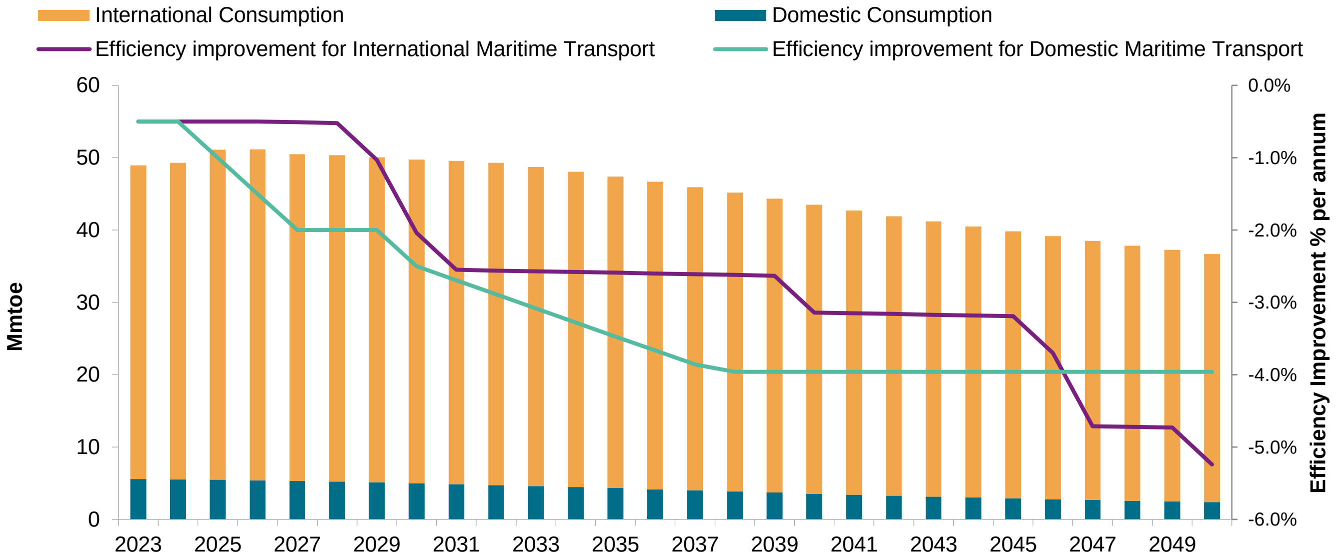
Note: Exogenous efficiency improvement describes the reduction in fuel consumption per passenger mile over time, thus a value of -2% means a 2% reduction each year in fuel consumption per passenger mile.

Figure 4.16 – Aviation Energy demand Outlook EU+ (MMtoe)



Source: S&P Global Commodity Insights.

Figure 4.17 – Maritime Fuel Demand Outlook



Source: S&P Global Commodity Insights.

Note: Efficiency improvement describes the reduction in fuel consumption per tonne mile over time, thus a value of -2% means a 2% reduction each year in fuel consumption per tonne mile.

Marine fuel demand is expected to peak in 2025 for both international and domestic categories as the maritime sector works to reduce carbon emissions. Driven by the International Maritime Organization's (IMO) decarbonization goals, the fleet will become more efficient through the Energy Efficiency Existing Index (EEXI) and the Energy Efficiency Design Index (EEDI). These initiatives will push operational ships to maintain high efficiency and require new builds to meet stricter targets.

Ship owners will adopt technology solutions such as wind-assistance devices, hull form adaptations and hull air lubrication to reduce drag, along with improved voyage and operational planning and use of on-shore power supply when in port to cut fuel consumption. New builds will increasingly use non-conventional fuels.

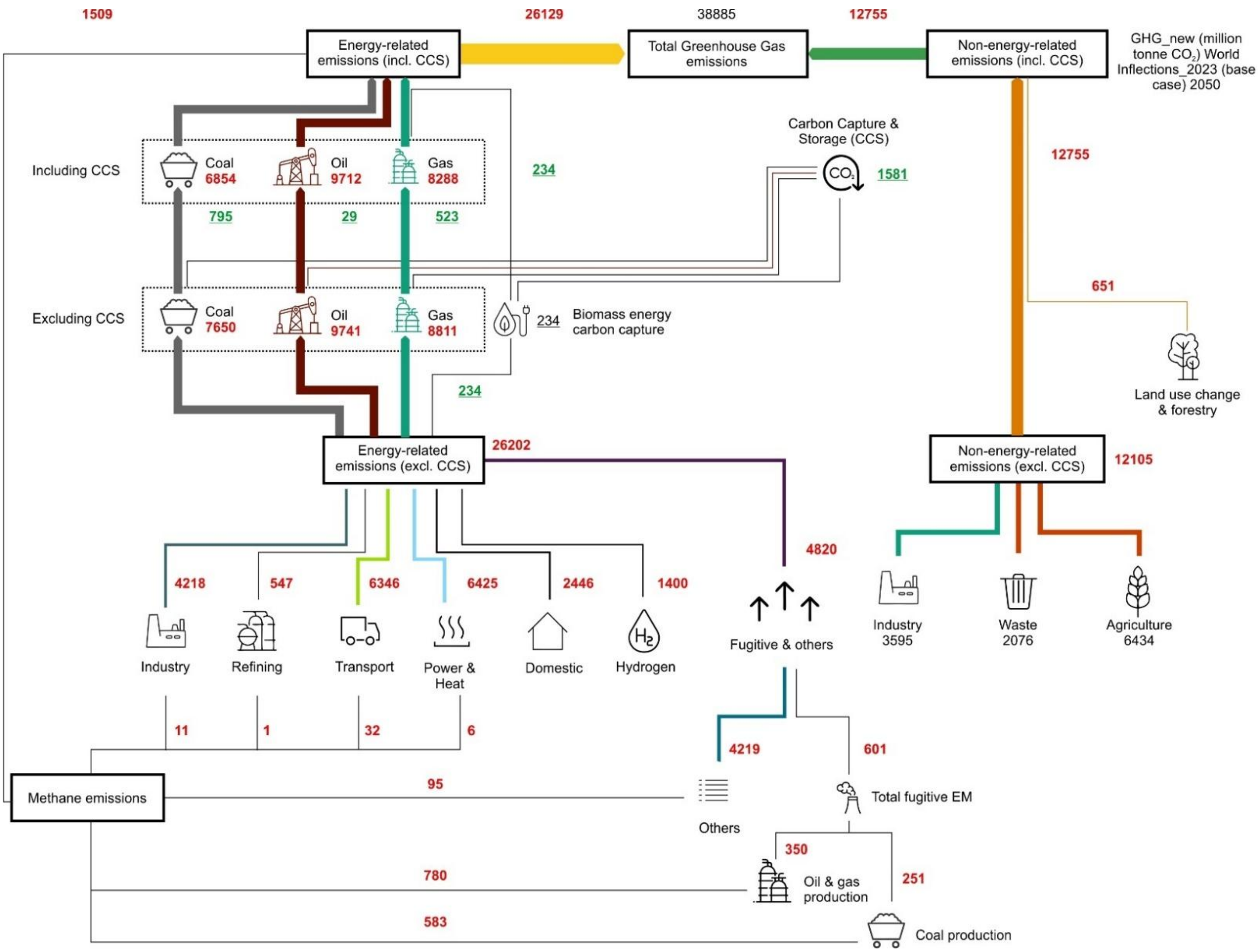
In regions like Europe, which has its own carbon reduction strategies, this trend will accelerate. Long-term, greater fleet utilization through pooling and changes in trade dynamics, driven by nearshoring, will combine with faster fleet replacement. More efficient vessels capable of carrying larger volumes will reduce ton-mile consumption, significantly lowering the overall fleet consumption.

More detailed information on Aviation and Marine energy demand can be found in Appendix A.

4.5 Emissions Model

Greenhouse gas emissions are calculated in tonnes of CO2-equivalent using a global warming potential of 100 years. Emissions are divided between energy-related emissions and non-energy emissions. The schematic below shows the GHG emission aggregation process – in this case S&P Global's projection of global emissions in 2050 under our 2023 Inflections (base case) scenario.

Figure 4.18 – GHG emissions aggregation



In this study we included the total CO2 emissions for production of 60% of the batteries required for EU+ electric vehicles manufacturing, it is assumed the other 40% would be batteries manufactured outside of the EU+.

Energy-related emissions are derived from the fossil fuel consumption by sector multiplied by the CO2 content of the fuels. In addition, non-CO2 energy-related emissions are included, e.g. nitrous-oxide (N2O), methane (CH4) and fluorocarbon-gases.

The International Panel on Climate Change (IPCC) guidelines on emission reporting are used as the basis for calculating GHG emissions from the energy sector. Emission factors are calculated for each fuel using the IPCC methodology and applied to the energy balance data for both the history and projections. The CO2 emissions from energy are detailed in the section below.

4.5.1 Non-Energy GHG Emissions

Non-energy related emissions are broken down into four categories:

- Agricultural
- Waste
- Industrial processes
- Land-use, land-use changes and forestry

4.5.2 Agriculture

The agricultural data is exclusive of energy use and comes from the Food and Agricultural Organisation (FAO). The following domains are identified by the FAO that make up the non-energy agricultural emissions:

- Enteric Fermentation – methane from ruminant animals
- Manure Management
- Rice Cultivation
- Synthetic Fertilizers
- Manure applied to Soils
- Manure left on Pasture
- Crop Residues
- Cultivation of Organic Soils
- Burning - Crop Residues
- Burning – Savanna

The FAO provide the following comment on total agriculture GHG emissions:

> "Agriculture Total contains all the emissions produced in the different agricultural emissions sub-domains, providing a picture of the contribution to the total amount of GHG emissions from agriculture. GHG emissions from agriculture consist of non-CO2 gases, namely methane (CH4) and nitrous oxide (N2O), produced by crop and livestock production and management activities. Computed at Tier 1 following IPCC Guidelines for National GHG Inventories; available by country, with global coverage and relative to the period 1990 to present, with annual updates, and projections for 2030 and 2050."

4.5.3 Industrial Processes

Non-energy Industrial Processes sector includes:

- CO_2 emissions from Cement Manufacture (CDIAC; Boden et al., 2015)
- N_2O emissions from Adipic and Nitric Acid Production (EPA, 2012)
- N_2O and CH_4 emissions from Other Industrial (non-agriculture) (EPA, 2012)
- F-gases: HFCs, PFCs, and SF6 (EPA, 2012)

CO_2 emissions from Cement Manufacture, drawn from CDIAC (Boden et al., 2015). N_2O emissions from Adipic and Nitric Acid Production are drawn from EPA (2012). Emissions estimates of high global warming potential (GWP) gases, namely HFCs, PFCs, and SF6, are drawn from EPA (2012).

4.5.4 Waste

Non-energy Waste sector includes CH_4 and N_2O emission from the following activities:

- CH_4 from Landfills (Solid Waste) (EPA, 2012)
- CH_4 from Wastewater Treatment (EPA, 2012)
- N_2O from Human Sewage (EPA, 2012)
- CH_4 and N_2O from Other (Waste) (EPA, 2012)

4.5.5 Land-Use, Land-Use Change and Forestry (LULUCF)

Land-Use and Forestry are again non-energy emissions and have the following domains with historic data from the FAO:

- Land Use Total
- Forest Land
- Cropland
- Grassland
- Burning – Biomass
- Forestry production and trade - forest products production, import and export statistics from 1961 onwards
- Forestry trade flows

Country-specific carbon prices are used to drive emissions towards a theoretical maximum emission reduction potential. The higher the carbon price the faster the shift towards the maximum reduction potential. However, a time delay is added by estimating the relationship to the ten-year moving average carbon price. This smooths out the carbon price trend and prevents sharp price increases from leading to too fast an increase in the same year, given the delays in implementation and the need for sustained price incentives.

The carbon price equating to the maximum potential (kmaxrpCO2$) can itself be related to the ratio of urban land area to total land area. The higher the ratio the higher the price. Alternatively, one can consider that the ratio of the rural area to total area is inversely related to the maximum carbon price – the lower the rural-to-total land area ratio the higher the price and the higher the rural-to-total ratio the lower the price.

In addition, some areas are not suitable for planting trees, grasses or other vegetation. In some countries the barren area is very large. We can use the share of barren land and combine it with the urban area share to get a view on the percentage of the land area that is not suitable for vegetation.

In SPGCI modelling, when almost all the land is available then the carbon price that equates with the maximum LUCF potential is set at US$300/t$CO_2$. As the available land declines as a share of the total land area so the maximum carbon price increases in an exponential manner. If none of the land area is available, then the maximum carbon price is set at US$1,500/t$CO_2$.

The maximum emission reduction potential is based on estimates from the IPCC Natural Climate Solutions (Table S3. Country level maximum mitigation potential with safeguards for 8 NCS pathways).

4.5.6 Energy related emissions

Emissions of carbon dioxide is calculated by each fossil fuel type, including oil by product and solid fuels by lignite and hard coal, for each of the end-use sectors, including industry sub-sectors, as well as for power generation. Carbon capture use and storage is assessed at the sector level and the CO_2 savings calculated based on the share of emissions that are sequestered. Emissions are aggregated by fuel type and sector totals. The sum of the emissions by sector is the total emission and matches the sum of the totals by fuel.

Table 4.1: Emission Factors Used in the CO_2 Model

		Tonne of CO_2/toe
Crude oil	co2fCRU	3.0695
Motor gasoline	co2fGSL	2.8978
Kerosene	co2fKRS	3.0067
Jet	co2fJTF	3.0067
Gas/diesel oil	co2fGDO	3.0988
Residual fuel oil	co2fRFO	3.2370
Liquefied petroleum gases	co2fLPG	2.6382
Naphtha	co2fNPH	3.0695
Other petroleum products	co2fOLQ	3.0695
Hard coal	co2fHCL	3.9573
Lignite	co2fLIG	4.2337
Natural gas	co2fNGS	2.3492
Biomass*	co2fCRW	4.6053

Source: S&P Global Commodity Insights.

* Biomass emissions are generally assumed to be carbon neutral as we assume biomass is from sustainable sources. What is consumed is regrown, thus absorbing the emissions. However, where biomass emissions are captured and sequestered, there is a net saving and the emission saving is calculated using the emission factor shown in the table.

Note: Net emissions from biofuels (biodiesel and biogasoline) are assumed at 23g of CO_2/MJ in 2020 and projected to gradually reduce to 5.5g of CO_2/MJ by 2050. This assumes that the production of biofuels itself becomes more sustainable over time as all energy sources used in production gradually decarbonize.

1 tonne oil equivalent (toe) is 41868 MJ

For vehicles, emissions from power train electricity, hydrogen and hydrogen derivates are considered zero in the CO_2 Model.

4.5.6.1 Methane related emissions

Emissions of methane are already incorporated into the non-energy GHG emissions. However, this is not the case for energy-related emissions. The methane emissions need to be added to the energy-related CO2 emissions to get the complete energy-related GHG emissions.

Methane emissions are derived from the sector level fuel consumption. Historic estimations are made between the sector methane emissions and the fossil-fuel energies consumed (coal, natural gas and oil). The coefficients are then used to estimate the methane emissions in the future.

The historic data comes from the EDGAR dataset (Reference: European Commission, Joint Research Centre (EC-JRC)/Netherlands Environmental Assessment Agency (PBL). Emissions Database for Global Atmospheric Research (EDGAR), release EDGAR v5.0 (1970 - 2015) of November 2019).

4.6 Max Electron Scenario

In the development of the Max Electron scenario, the foundational framework rests upon S&P Global's Green Rules Scenario, but with the addition of assumptions discussed below.

The Max Electron Scenario meets the net zero GHG emission objective by 2050 for the EU+ set of countries, strictly meeting all requirements of 'Fit for 55' and exceeding heavy-duty vehicles CO_2 standards, achieved via an accelerated rate of electrification across various modes of transportation, more aggressive than Green Rules.

The Max Electron scenario assumes an unprecedented rate of electrification across various modes of transportation. This scenario relies on the widespread adoption of electric vehicles (LDV and HDV), transforming the landscape of personal and commercial transportation and considers electrification possibilities in the aviation and marine sectors. The Max Electron Scenario represents a comprehensive and innovative approach to reducing carbon emissions, fostering clean energy solutions, and ushering in a new era of electrified mobility. Leading up to 2030, high rates of electrification are required to meet ETS II requirements in 2030.

For LDV, there is a post 2035 internal combustion engine ban for new sales of LDV (passenger and LCV) in the road transportation sector for the Max Electron scenario. All these sales are moved to Battery Electric Vehicles to maintain the vehicle population with resultant reduction in liquid fuels demand and increase in electricity demand in the Max Electron scenario.

For HDV (Heavy Duty Vehicle) in Max Electron, there is a ban on new sales of diesel and gasoline engine post 2035 for the HDV section of road transportation sector. The scenario also sees stronger penetration of battery and hydrogen fuel-cell trucks in HDV sector demand after 2035. This is more stringent than the heavy-duty vehicles CO_2 standards which allows some sales of ICE-vehicles post- 2040 to reach 90% emission reduction target of annual new sales.

4.6.1 Final End Use Energy Demand

Final end use energy demand includes below sub-sectors:

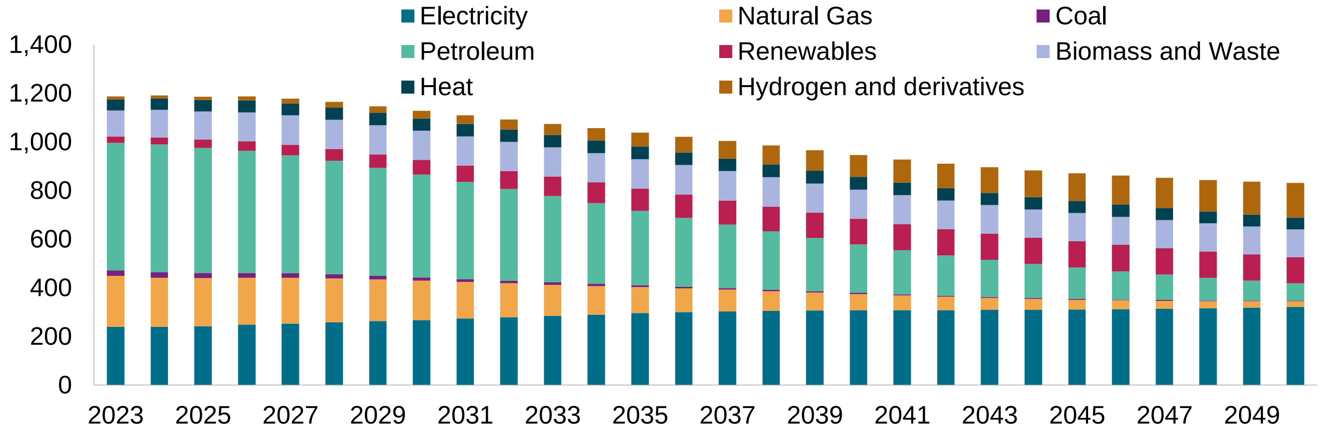
- Transport sector
- Industrial sector
- Agriculture sector
- Residential heating sector
- Commercial heating sector
- Feedstock

The outcome of the Final end use energy demand in Max Electron scenario highlights the overall decline in Final end use energy demand due to massive electrification and efficiency gains in different sub sectors as compared to current level. Overall share of petroleum in Final end use energy demand shrinks to only 8.5% by 2050 in Max Electron scenario. For decarbonization and achieving a net-zero future, electricity emerges as a cornerstone solution due to its potential for renewable integration and reduced environmental impact.

Electricity gains 39% of Final end use energy demand in all sub sectors by 2050. Renewable demand i.e., small-scale nonelectric renewables (e.g., solar thermal water heating, heat pumps), mostly come from residential and commercial heating along with part of industrial and agriculture sector, increases its overall share to 13% by 2050, displacing the traditional hydrocarbon energy sources for heating in overall energy demand.

The majority of hydrogen and derivatives demand come from the Transport and Industrial sectors, where hydrogen from electrolysis is considered an important source to decarbonize the overall energy mix in both scenarios. Overall hydrogen, derivatives and bio mass (includes bio-fuels and traditional bio mass) have 31% of total energy demand by 2050. Figure 4.19 shows the Final end use energy demand outlook for the Max Electron scenario. This excludes transformation energy, which is explained in the following section.

Figure 4.19 – Final end use energy demand outlook – Max Electron scenario – excludes Transformation Energy (MMtoe)



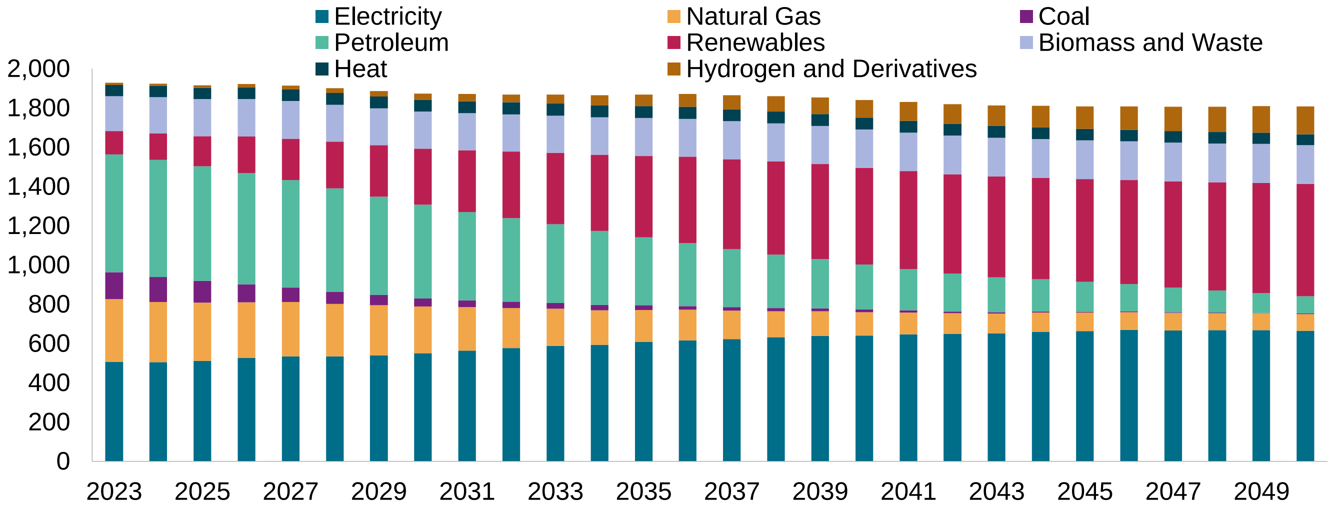
Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

4.6.2 Total Energy Demand

Total Energy demand includes Final end use energy demand and Transformation energy demand. Transformation energy use is the amount of primary energy and electricity consumed to transform into a final form the energy used by consumers for all energy uses. It includes energy used by the transformation sector for its own use and conversion, as well as distribution losses and fuels consumed by nonenergy users, who use them as feedstocks for manufacturing, particularly petrochemicals.

In Max Electron, the total energy demand experiences a slight reduction due to electrification and efficiency gains. By 2050, petroleum energy demand decreases to just 5% of the total energy demand in max electron scenario. Meanwhile, the demand for renewables rises to 31.6% of the total energy demand, driven by increased use of renewable direct electricity and green hydrogen production. In Max Electron the overall demand of bio energy is 11 % of total energy demand.

Figure 4.20 – Final end use energy demand outlook for Max Electron scenario (MMtoe)



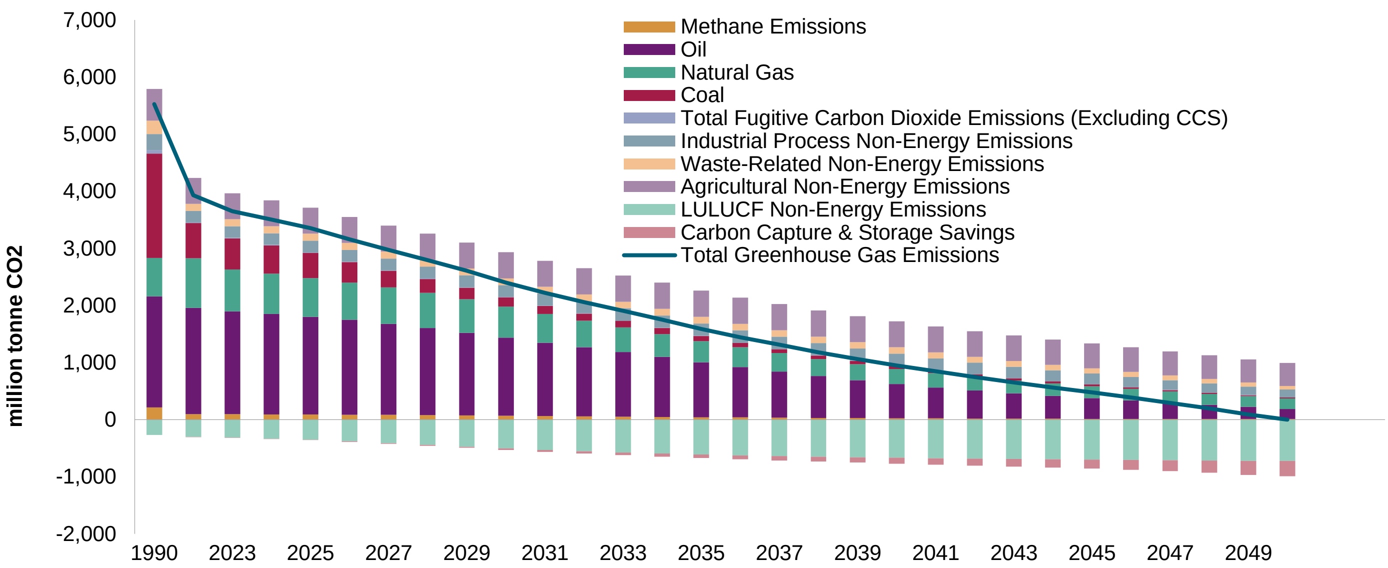
Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Note: "electricity" in transformation sector includes electricity demand in refining sector, other energy sector (oil and gas extraction, coal mining), and own use (within power plants) and distribution losses, so this is consumption of electricity.
"Renewables" includes solar, wind, tidal, geothermal and hydro for electricity, district heat, and hydrogen generation, so this is renewables input to the production of electricity, heat and hydrogen/hydrogen derivatives

4.6.3 Total Emissions

Overall Emissions in EU+ Max Electron scenario, as shown in Figure 4.21, reduces from 5526 million tonnes CO2 in 1990 to zero in 2050 - i.e., an overall reduction of 100% from the 1990 level.

Figure 4.21 – Max Electron Scenario Total GHG Emissions



Source: S&P Global Commodity Insights.

4.7 More Molecule Scenario

In the development of the More Molecule scenario, the foundational framework also rests upon the S&P Global Green Rules scenario. More Molecule is also aligned with the EU's net zero goals and either meets or exceeds the sub-targets set in Fit for 55, RefuelEU Aviation and FuelEU Maritime, except for certain emission standards for new vehicles. In More Molecule, a key assumption underpinning the scenario is that electricity penetration will be lower within the transport sector, as compared to Max Electron.

More Molecule envisions a landscape where plug-in hybrids remain an option for road transport post 2035, in addition to “zero-emission engines”, with substitution for traditional fuels by increased utilization of low carbon fuels as well as electrification. These low carbon fuels primarily encompass hydrogen and its derivatives such as synthetic fuels, ammonia, e-methanol etc., and advanced biofuels. By pivoting towards these innovative and low carbon alternatives, More Molecule seeks to achieve the EU+ emissions reduction target by utilizing more low carbon fuels, particularly biofuels, compared to Max Electron. Leading up to 2030, high rates of electrification are required to meet ETS II requirements in 2030.

4.7.1 Final End Use Energy Demand

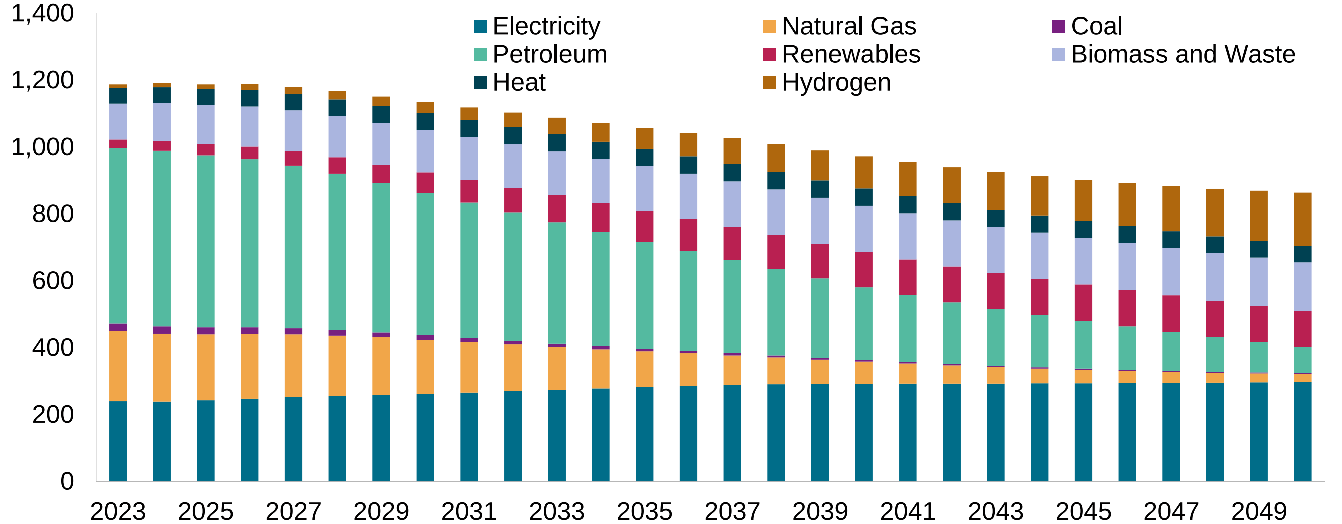
Final End Use energy demand includes below sub-sectors:

- Transport sector
- Industrial sector
- Agriculture sector
- Residential heating sector
- Commercial heating sector
- Feedstock

The outcome of the Final End Use energy demand in More Molecule scenario highlights the overall decline in Final End Use energy demand with efficiency gains. However, overall, the More Molecule scenario total final energy demand is 33 MMtoe higher than Max Electron scenario due to lower efficiency of providing energy by combusting molecules as compared to providing energy directly by electricity. Overall share of petroleum in Final End Use energy demand shrinks to 9% by 2050 in More Molecule scenario. For decarbonization and achieving a net-zero future, low carbon fuels are utilized with a more limited penetration of battery electric vehicles compared to the Max Electron scenario. By 2050, electricity gains 34% of total energy demand in all sub sectors by 2050. Renewable demand i.e., small-scale nonelectric renewables (e.g., solar thermal water heating, heat pumps), mostly came from residential and commercial heating along with part of industrial and agriculture sector, increases its overall share to 13% by 2050, displacing the traditional hydrocarbon energy sources for heating in overall energy demand.

The majority of hydrogen and derivatives demand comes from the Transport and Industrial sectors, where hydrogen from electrolysis is considered an important source to decarbonize the overall energy mix in both scenarios. Overall hydrogen and derivatives and biomass (include biofuels and traditional bio mass) have 36% of total energy demand by 2050 in More Molecule scenario.

Figure 4.22 – Final End Use energy demand outlook for More Molecule scenario – excludes Transformation Energy (MMtoe)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.
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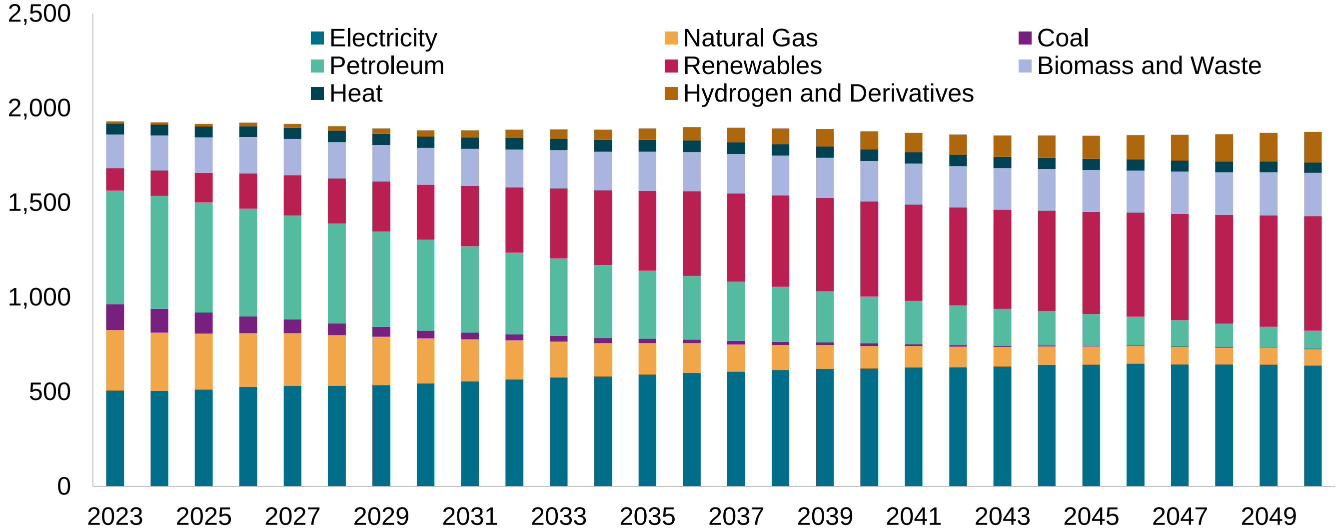
4.7.2 Total Energy Demand

Total Energy demand includes Final end use energy demand and Transformation energy demand. Transformation energy use is the amount of primary energy and electricity consumed to transform into a final form the energy used by consumers for all energy uses. It includes energy used by the transformation sector for its own use and conversion, as well as distribution losses and fuels consumed by nonenergy users, who use them as feedstocks for manufacturing, particularly petrochemicals. End-use energy demand is exactly that – the energy directly used by consumers in all forms.

In the More Molecule scenario, the total energy demand experiences a slight reduction due to electrification and efficiency gains. By 2050, petroleum energy demand decreases to just 5% of the total energy demand. Meanwhile, the demand for renewables energy rises to 32.3% of the total energy demand, driven by increased use of renewable direct electricity and green hydrogen production. The overall demand of bio energy is 12 % of total energy demand in More Molecule.

Figure 4.23 – Final end use energy demand outlook for More Molecule scenario (MMtoe)



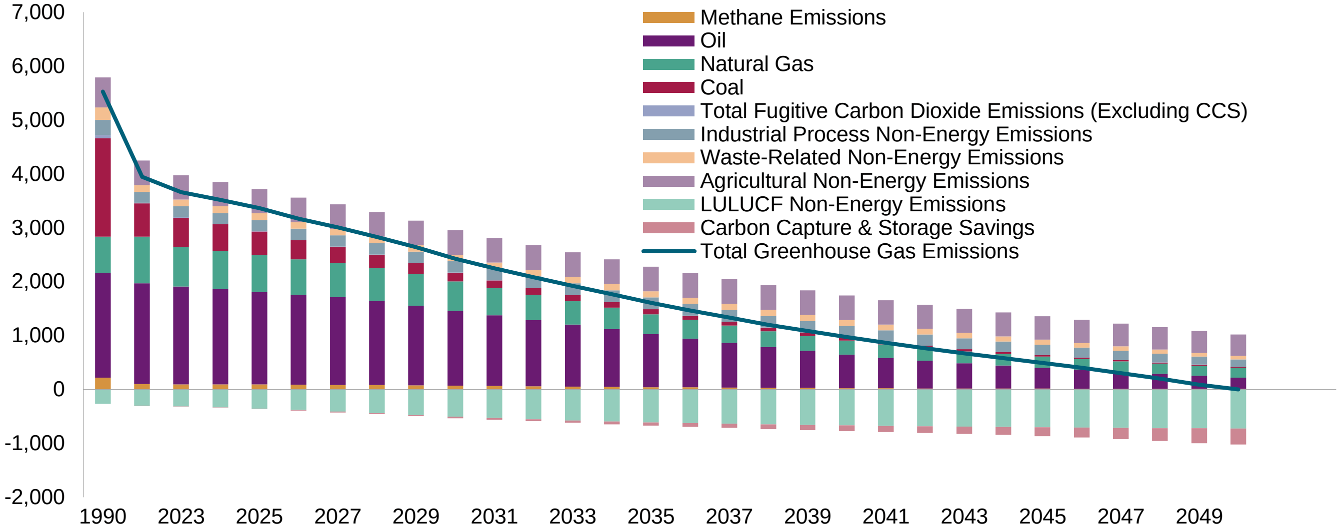
Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Note: "electricity" in transformation sector includes electricity demand in refining sector, other energy sector (oil and gas extraction, coal mining), and own use (within power plants) and distribution losses, so this is consumption of electricity.
"Renewables" includes solar, wind, tidal, geothermal and hydro for electricity, district heat, and hydrogen generation, so this is renewables input to the production of electricity, heat and hydrogen/hydrogen derivatives

4.7.3 Total Emissions

Overall Emissions in EU+ More Molecule, as shown in Figure 4.24, reduces from 5526 million tonnes CO2 in 1990, 3944 million tonnes CO2 in 2022, to zero by 2050 - i.e. an overall reduction of 100% from the 1990 level.

Figure 4.24 – More Molecule Scenario Total GHG Emissions (million tonnes CO_2)

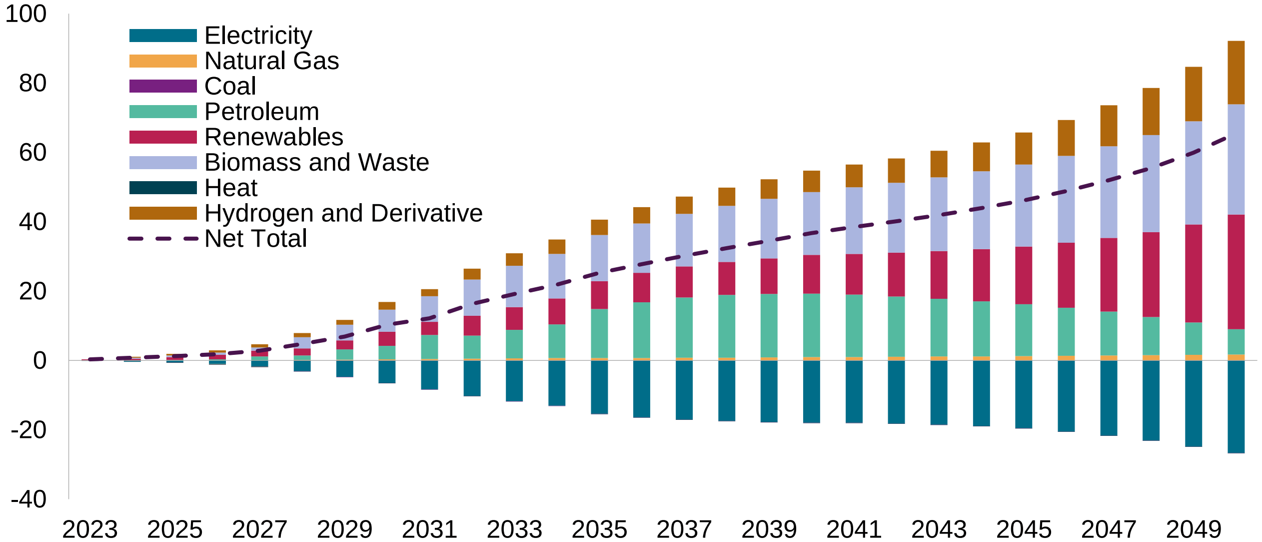


Source: S&P Global Commodity Insights.

4.8 Max Electron and More Molecule Scenario Comparison

Comparing the total energy demand for the More Molecule and Max Electron scenarios by 2050, the More Molecule scenario has 65.5 MMtoe more overall energy demand than the Max Electron scenario. This difference is primarily due to the additional renewables needed for energy transformation to produce green hydrogen and the higher demand for biofuels in the final energy mix. These differences are shown in Figures 4.25.

Figure 4.25 – Delta total energy demand outlook: More Molecule Minus Max Electron (MMtoe)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

"Renewables" includes solar, wind, tidal, geothermal and hydro for electricity, district heat, and hydrogen generation, so this is renewables input to the production of electricity, heat and hydrogen/hydrogen derivatives

Values greater than zero reflect a greater demand in the More Molecule scenario compared to Max Electron scenario.

Table 4.2 Breakdown of Total Electricity Demand by Scenario

	MMToe	
	2050	**2050**
	Max Electron	**More Molecule**
Road	*64*	*52*
Aviation	*7*	*0*
Maritime	*5*	*0*
Rail	*14*	*14*
Others	*1*	*1*
Total Electricity Demand in Transport	91	67
Total Industry Electricity Demand	87	87
Residential Electricity Demand	84	84
Agriculture Electricity Demand	6	6
Commercial Electricity Demand	54	54
Final Electricity direct use Demand	**321**	**297**
Transformation electricity demand for non-renewable generation	*345*	*342*
Transformation electricity demand for renewable generation	*464*	*497*
Transformation Electricity Demand	**809**	**839**
Total EU+ Electricity Demand	**1130**	**1136**

Note: "electricity" in transformation sector includes electricity demand in refining sector, other energy sector (oil and gas extraction, coal mining), and own use (within power plants) and distribution losses, so this is consumption of electricity.

"Renewables" includes solar, wind, tidal, geothermal and hydro for electricity, district heat, and hydrogen generation, so this is renewables input to the production of electricity, heat and hydrogen/hydrogen derivatives

The total electricity demand is approximately the same in both scenarios (less than 1% difference)

When comparing electricity demand in both scenarios, the final electricity direct use demand is 24 MMtoe higher in the Max Electron scenario compared to the More Molecule scenario. This increased demand in the Max Electron scenario is attributed to the electricity requirements in transportation sector.

However, in terms of transformation electricity demand, More Molecule has a total that is 30 MMtoe higher than Max Electron. This increase is primarily due to the higher demand for renewable electricity used to make hydrogen and the RFNBO/e-Fuels.

Key parameters for the two scenarios are shown in Tables 4.3 to 4.5. It is observed that leading up to 2030, high rates of electrification are needed to meet the requirements of ETS II for both scenarios. Beyond 2030, for Max Electron, high electrification continues and accelerates due to the ban on the sale of ICE vehicles in 2035. While in More Molecule, BEV sales are lower, due to the continued sale of ICE vehicles post 2035. This results in the passenger vehicle fleet comprising 82.3% BEV's in Max Electron and 57.5% BEV's in Max

Molecule in 2050. Heavy Duty vehicles consuming liquid fuels are deemed to represent still 41% in Max Electron and 72% in More Molecule.

Table 4.3 Key Parameters for EU+ Common to Both Scenarios

Parameter	Unit	2024	2030	2040	2050	2050 vs. 2024
Real GDP	real billion US$	21,088	22,804	25,498	28,676	136%
Passenger vehicle road km	km	12191	11602	10527	9507	78%
Light Commercial Vehicle road km	km	21993	20638	17187	16120	73%
Total Freight	million tonne km	2,661,002	2,990,866	3,589,405	4,341,215	163%
Road Freight	million tonne km	2,091,966	2,155,634	1,947,785	1,646,739	79%
Rail Freight	million tonne km	569,035	835,232	1,641,620	2,694,476	474%
Rail Electrification rate	%	74.3%	77.2%	87.0%	90.7%	122%
Total Flights	No. of flights (millions)	6.16	6.65	7.63	9.01	146%
International Flights	No. of flights (millions)	4.75	5.13	5.93	7.07	149%
Domestic Flights	No. of flights (millions)	1.41	1.52	1.70	1.93	137%
Marine Domestic Consumption	MMtoe	5.55	5.02	3.57	2.38	43%
Marine International consumption	MMtoe	43.73	44.74	39.93	34.29	78%
Number of Households	million	232.91	240.68	246.34	247.88	106%
Population	million people	529.8	527.7	522.0	510.9	96%
Power Generating Capacity	MW	1,379,334	1,917,252	2,976,800	3,783,689	274%
Nuclear Generating Capacity	MW	112,727	110,439	107,356	93,123	83%
Renewable Power Generating Capacity	MW	897,243	1,533,377	2,778,758	3,669,047	409%
% Renewable Capacity	%	65.0%	80.0%	93.3%	97.0%	
Total Generation	TWh	3289.62	4068.64	5708.11	6545.46	199%
Nuclear	TWh	697.73	631.20	492.46	346.51	50%
Renewable Generation	TWh	1857.23	3195.82	5169.75	6152.27	331%
% Renewable Generation	%	56.5%	78.5%	90.6%	94.0%	

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate.)

Table 4.4 Key Parameters for EU+ Max Electron Scenario

Parameter	Unit	2023	2024	2030	2040	2050	2050 vs. 2024
Total Number of Cars	No. of vehicles	295,448,376	299,990,776	301,539,581	257,743,747	217,509,063	73%
Number of Gasoline Cars	No. of vehicles	158,030,946	152,933,813	104,735,485	30,922,210	5,141,290	3%
Number of Diesel Cars	No. of vehicles	109,252,313	106,137,702	73,722,282	21,791,137	3,497,337	3%
Number of Hybrid Cars	No. of vehicles	11,769,994	17,664,316	42,121,837	32,382,232	6,089,396	34%
Number of Plug-in Hybrid Cars	No. of vehicles	2,611,877	4,941,132	18,739,067	22,785,613	13,007,773	263%
Number of Battery Electric Cars	No. of vehicles	5,952,259	10,758,639	55,922,659	142,736,660	178,984,580	1664%
% EV in Fleet	%	2.0%	3.6%	18.5%	55.4%	82.3%	2295%
Total Number of LCV	No. of vehicles	30,812,130	27,899,072	23,866,848	25,176,581	25,424,872	91%
Number of Gasoline LCV	No. of vehicles	2,659,334	2,333,987	3,646,320	553,192	18,910	1%
Number of Diesel LCV	No. of vehicles	26,505,422	22,004,005	7,563,841	341,227	1,387	0%
Number of Hybrid LCV	No. of vehicles	141,420	159,785	307,170	240,469	10,873	7%
Number of Plug-in Hybrid LCV	No. of vehicles	229,358	549,935	1,918,436	2,121,668	1,142,522	208%
Number of Battery Electric LCV	No. of vehicles	876,373	2,490,928	10,314,352	21,622,331	23,365,445	938%
% EV in Fleet	%	2.8%	8.9%	43.2%	85.9%	91.9%	1029%
Total Number of HGV	No. of vehicles	7,793,782	7,744,347	7,918,523	7,348,305	6,354,557	82%
Number of Gasoline HGV	No. of vehicles	59,616	60,421	242,077	165,725	100,995	167%
Number of Diesel HGV	No. of vehicles	7,606,121	7,557,420	6,897,509	3,907,266	2,492,618	33%
Number of BEV HGV	No. of vehicles	32,734	35,876	689,060	2,166,934	1,803,092	5026%
Number of Hydrogen(1) HGV	No. of vehicles	9,180	9,158	17,366	1,037,628	1,906,950	20823%
Total Greenhouse Gas Emissions	million tonne CO2	3,650	3,506	2,400	948	0	-
LULUCF Non-Energy Emissions	million tonne CO2	(315)	(333)	(505)	(667)	(724)	217%
Carbon Capture and Storage	million tonne CO2	(0.3)	(0.5)	(27.3)	(104.1)	(266.4)	50276%

(1) Includes hydrogen, ICE and fuel cell

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate.)

Table 4.5 Key Parameters for EU+ More Molecule Scenario

Parameter	Unit	2023	2024	2030	2040	2050	2050 vs. 2024
Total Number of Cars	No. of vehicles	295,448,376	299,990,776	301,539,581	257,743,738	217,509,070	73%
Number of Gasoline Cars	No. of vehicles	158,030,946	152,933,813	104,735,485	30,956,308	5,193,143	3%
Number of Diesel Cars	No. of vehicles	109,252,313	106,137,702	73,722,282	21,931,370	3,708,240	3%
Number of Hybrid Cars	No. of vehicles	11,769,994	17,664,316	42,121,837	32,404,123	6,113,902	35%
Number of Plug-in Hybrid Cars	No. of vehicles	2,611,877	4,941,132	18,739,067	43,106,857	66,276,770	1341%
Number of Battery Electric Cars	No. of vehicles	5,952,259	10,758,639	55,922,659	122,025,641	124,988,025	1162%
% EV in Fleet	%	2.0%	3.6%	18.5%	47.3%	57.5%	1602%
Total Number of LCV	No. of vehicles	30,812,130	27,899,072	23,866,848	25,176,581	25,424,871	91%
Number of Gasoline LCV	No. of vehicles	2,659,334	2,333,987	3,646,320	553,192	18,910	1%
Number of Diesel LCV	No. of vehicles	26,505,422	22,004,005	7,563,841	341,227	1,387	0%
Number of Hybrid LCV	No. of vehicles	141,420	159,785	307,170	250,600	21,463	13%
Number of Plug-in Hybrid LCV	No. of vehicles	229,358	549,935	1,918,436	4,559,106	7,224,854	1314%
Number of Battery Electric LCV	No. of vehicles	876,373	2,490,928	10,314,352	19,170,304	17,263,241	693%
% EV in Fleet	%	2.8%	8.9%	43.2%	76.1%	67.9%	760%
Total Number of HGV	No. of vehicles	7,793,782	7,744,347	7,918,523	7,348,305	6,354,557	82%
Number of Gasoline HGV	No. of vehicles	59,616	60,421	242,077	165,725	100,995	167%
Number of Diesel HGV	No. of vehicles	7,606,121	7,559,296	7,500,106	6,076,081	4,459,733	59%
Number of BEV HGV	No. of vehicles	32,734	34,000	86,463	132,853	190,461	560%
Number of Hydrogen(1) HGV	No. of vehicles	9,180	9,158	17,366	902,894	1,552,467	16952%
Total Greenhous Gas Emissions	million tonne CO2	3,661	3,516	2,423	1,013	0	-
LULUCF Non-Energy Emissions	million tonne CO2	(315)	(333)	(505)	(667)	(724)	217%
Carbon Capture and Storage	million tonne CO2	(0.3)	(0.5)	(27.3)	(106.0)	(295.6)	55786%

(1) Includes hydrogen, ICE and fuel cell

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate.)

5 LP Modelling

5.1 LP Model Main features

5.1.1 Introduction

LP modelling, also known as linear programming modelling, is a mathematical technique used to optimize resource allocation and decision-making in various industries. LP models involve maximizing or minimizing an objective function while considering a set of linear constraints. These models are widely used in operations research, supply chain management, logistics, finance, and other fields.

In LP modelling, decision variables are defined, representing the quantities to be determined. Objective functions are formulated to express the goal to be achieved, such as maximizing profit or minimizing costs. Constraints are established to represent limitations or restrictions on the decision variables, such as resource availability or capacity constraints.

LP models are solved using optimization algorithms to find the optimal values for the decision variables that satisfy the constraints and optimize the objective function. This allows organizations to make informed decisions, improve efficiency, and achieve optimal outcomes in their operations.

5.1.2 Role of LP Model

LP model constitutes the entire refinery process, including crude oil inputs, processing units, and product outputs. It considers various factors such as feedstock availability, product demand, operational constraints, and market conditions. By using mathematical optimization techniques, LP model identifies the optimal production plan that maximizes profitability while meeting operational and market constraints.

S&P Global's proprietary LP model was utilized during this study to generate the margin forecast for various years like 2024, 2030, 2040 and 2050 based on the inputs like selected crude slate, production levels, product mix, bio-feedstocks coprocessing, and use of green hydrogen. It enabled to optimize refineries operations, reduce costs, improve efficiency, and maximize profitability to generate net variable margin.

5.1.3 Refineries covered in the assessment

For this study, we analyzed a total of 86 refineries operational in April 2024. Among these, 78 are classified as main fuel refineries, while 8 are categorized as specialty refineries. Together, these refineries have a combined crude and condensate processing capacity of approximately 13.3 million barrels per day.

Table 5.1– EU+ Refineries List

No.	Refinery	Country	Owner	Capacity,'000 bbl/d
1	Schwechat	Austria	OMV	209
2	Antwerp	Belgium	Total Energies	338
3	Antwerp	Belgium	ExxonMobil	307
4	Burgas	Bulgaria	Lukoil	139
5	Rijeka	Croatia	INA	90

No.	Refinery	Country	Owner	Capacity,'000 bbl/d
6	Litvinov	Czech Republic	CRC (PKN Orlen/ENI/Shell)	103
7	Kralupy	Czech Republic	CRC (PKN Orlen/ENI/Shell)	63
8	Kalundborg	Denmark	Equinor	110
9	Fredericia	Denmark	Crossbridge Energy	70
10	Porvoo	Finland	Neste	200
11	Gonfreville	France	Total Energies	255
12	Port-Jerome	France	ExxonMobil	233
13	Donges	France	Total Energies	230
14	Lavera	France	Petroineos	218
15	Fos	France	Rhône Energies	133
16	Feyzin	France	Total Energies	116
17	Rheinland	Germany	Shell	346
18	Karlsruhe	Germany	MiRO	302
19	Gelsenkirchen	Germany	BP	257
20	Leuna	Germany	Total Energies	227
21	Schwedt	Germany	PCK (Shell/Rosneft/ENI)	220
22	Bayern oil	Germany	ENI/VARO/ROSNEFT	215
23	Ingolstadt	Germany	Gunvor	106
24	Harburg (Holborn)	Germany	Tamoil	94
25	Lingen	Germany	BP	91
26	Heide	Germany	RHG (Klesch)	91
27	Burghausen	Germany	OMV	72
28	Wilhelmshaven	Germany	Hestya Energy BV	60
29	Harburg*	Germany	Nynas	50
30	Brunsbuttel*#	Germany	Total Energies	17
31	Hamburg/Neuhoff*#	Germany	H&R	15
32	Salzbergen*#	Germany	H&R	7
33	Agii Theodori (Corinth)	Greece	MotorOil Hellas	185
34	Aspropyrgos	Greece	HelleniQ	147
35	Elefsis	Greece	HelleniQ	100
36	Thessaloniki	Greece	HelleniQ	92
37	Szazhalombata (Duna)	Hungary	MOL	161
38	Whitegate	Ireland	IRVING OIL	71
39	ISAB Priolo & Melilli	Italy	ISAB Refinery (Lukoil)	320

No.	Refinery	Country	Owner	Capacity,'000 bbl/d
40	Sarroch	Italy	SARAS	300
41	RAM (Milazzo)	Italy	ENI/KPI	202
42	Sannazzaro	Italy	ENI	200
43	Augusta	Italy	Sonatrach	198
44	Trecate	Italy	ExxonMobil/API	132
45	Livorno	Italy	ENI	84
46	Taranto	Italy	ENI	120
47	Falconara	Italy	API	83
48	Busalla	Italy	IPLOM	40
49	Mazeikiu (Lietuva)	Lithuania	PKN Orlen	207
50	Pernis	Netherlands	Shell	406
51	NRC (Rotterdam)	Netherlands	BP	380
52	Rotterdam	Netherlands	ExxonMobil	192
53	Vlissingen (Zeeland)	Netherlands	Total Energies/Lukoil	147
54	Rotterdam	Netherlands	Vitol (VPR Energy)	85
55	Mongstad	Norway	Equinor	200
56	Plock	Poland	PKN Orlen	327
57	Gdansk	Poland	PKN Orlen/Saudi Aramco	210
58	Trzebinia	Poland	PKN Orlen	8
59	Jedlicze	Poland	PKN Orlen	3
60	Sines	Portugal	Galp Energia	220
61	Navodari (Constanza)	Romania	Petromidia (KMG International)	110
62	Ploiesti	Romania	Petrobrazi (OMV Petrom)	91
63	Ploiesti	Romania	Petrotel (Lukoil)	48
64	Slovnaft (Bratislava)	Slovakia	MOL	115
65	San Roque	Spain	CEPSA	240
66	Bilbao	Spain	Repsol	220
67	Cartagena	Spain	Repsol	220
68	Huelva (La Rabida)	Spain	CEPSA	220
69	Tarragona	Spain	Repsol	186
70	Puertollano	Spain	Repsol	150
71	La Coruna	Spain	Repsol	120
72	Castellon	Spain	BP	105
73	ASESA*	Spain	CEPSA/REPSOL	21

No.	Refinery	Country	Owner	Capacity,'000 bbl/d
74	Lysekil	Sweden	Preem	220
75	Gothenburg	Sweden	Preem	113
76	Gothenburg	Sweden	St1 Refinery	78
77	Nynasham*	Sweden	Nynas	28
78	Gothenburg*	Sweden	Nynas	13
79	Cressier	Switzerland	Varo Holdings	68
80	Fawley	UK	ExxonMobil	258
81	Humber	UK	Phillips66	221
82	Pembroke	UK	Valero	210
83	Stanlow	UK	Essar	206
84	Grangemouth	UK	Petroineos	145
85	Humberside (Lindsey Oil Refinery)	UK	Prax Group	113
86	Eastham*	UK	Nynas/Shell	27
	EU+ Total Capacity			**13345**

The capacities mentioned refer to crude or condensate capacity, except for those indicated with '#', which represent vacuum distillation capacity.

*Specialty refineries

Note: The list is sorted in alphabetical order by country and decreasing capacity

Notably, two refineries, Grangemouth and Livorno, have recently announced closures. Additionally, the Wesseling refinery, part of the Shell Rheinland complex, is scheduled to close by 2025, and the Glensenkirchen refinery has announced its plan to close one third of its crude processing operations by 2025. These refineries are not considered for LP runs in 2030, 2040 or 2050.

5.1.4 Refinery level & regional LP model

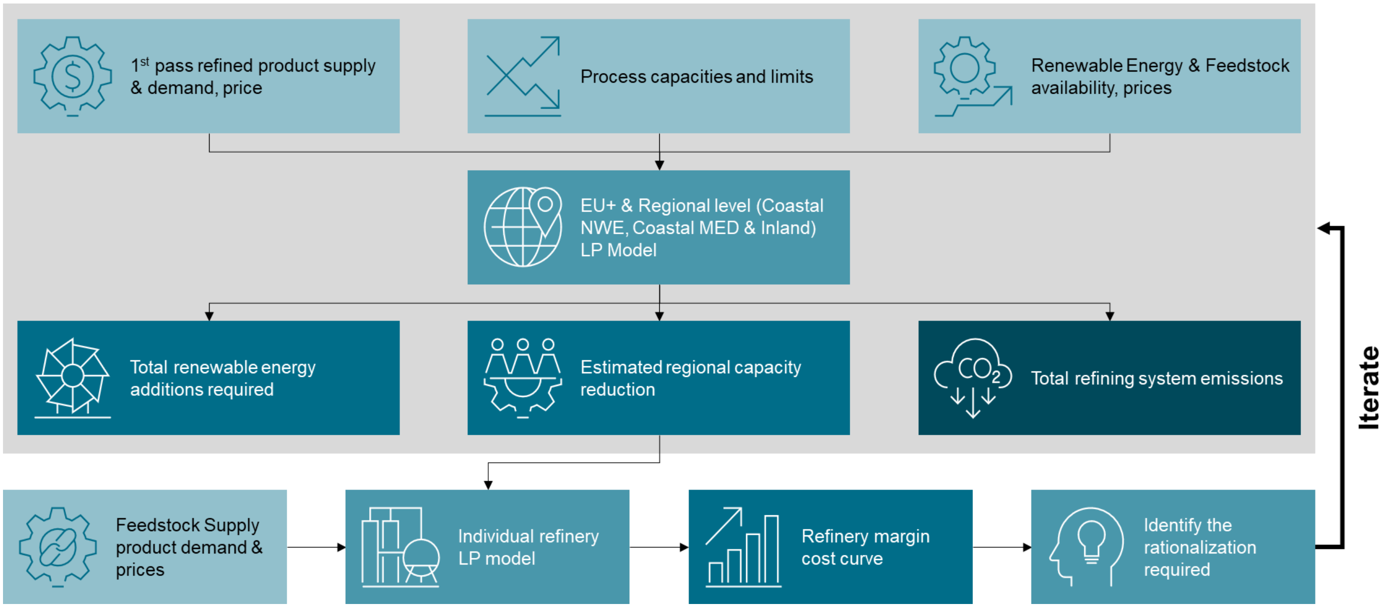
S&P Global utilized its proprietary LP model for this analysis, leveraging existing data and forecasts from our comprehensive database to determine refinery feedstock, unit capacities, product yields, utilities, and emission estimates. A single aggregated PIMS LP model was developed to represent European refineries, as listed in Table 5.1. This unified model was also applied to aggregate refining capacity at the regional level (EU+, Coastal NWE[3], Coastal MED[4], and Inland[5]). Impact assessments were initially conducted at the regional level to gauge the necessary capacity reductions to align with overall demand. Subsequently, individual refinery LP runs were executed to generate margin curves. Refineries with estimated negative net margins were identified for rationalization, and the results were iteratively fed back to the regional level to achieve a supply-demand balance. The chart below shows an illustrative workflow:

[3] Countries considered in Coastal NWE region are Belgium, Denmark, Estonia, Finland, Ireland, Latvia, Lithuania, Luxembourg, Netherlands, Norway Sweden, Western France, Western Germany, Western Poland, United Kingdom.

[4] Countries considered in Coastal MED region are Croatia, Cyprus, Greece, Italy, Malta, Portugal, Slovenia, Eastern France, Spain.

[5] Countries considered in Inland region are Austria, Bulgaria, Czech Republic, Hungary, Romania, Slovakia, Eastern Germany, Eastern Poland, Switzerland.

Figure 5.1 – Illustration of LP analysis methodology



5.1.5 Unit operation vectors and stream routing

The operations for different process units: Hydrotreaters, Catalytic Reformers, Hydrocrackers, Fluid Catalytic crackers, Coker, SDA (Solvent De-asphalting), Visbreaker, Hydrogen Manufacturing (SMR process) and associated units are represented using yield and quality vectors based on S&P Global's internal databases. LP models for each process unit and necessary associated units such as feed poolers, etc. are developed using these yield and quality vectors. This model aggregates individual refinery data into a single, large refinery model. Such aggregation can lead to over-optimization (an under-constrained system) because all process unit capacities are available simultaneously, significantly increasing the system's degrees of freedom. To mitigate this risk, a calibration run is performed with year 2021 selected as reference year. Input data was sourced from publicly available Eurostat data. The main inputs required for calibrating the LP model include the European average crude oil slate, refinery utilization, other imported feedstocks, the demand and quality of finished products, and the quantities of exported products.

As some bio feedstocks undergo similar processing to traditional petroleum feedstocks, we have modelled various bio-feedstocks (e.g., animal fat, waste vegetable oil, palm oil, rapeseed oil) for co-processing in existing refinery hydrotreaters. This modelling approach enables us to model the production of renewable biofuels, including renewable diesel (as transportation fuel) and sustainable aviation fuel by co-processing. Regional and country-level bio feedstock availability is considered based on S&P Global's Supply outlook; however, they are adjusted for individual refineries based on the co-processing capacity assumptions. Palm oil co-processing from 2030 onwards is not considered. Although most hydrotreaters can process up to 5% biofuels without significant modifications to plant configuration, biofuel co-processing is calibrated based on the expected production from refineries in 2024. This calibration indicates that ~2% of the aggregated hydrotreater capacity in the EU+ will be used for biofuel co-processing. As biofuel processing gains momentum, this figure is projected to increase to ~5% of total hydrotreater capacity by 2050 and used as LP input for biofuel co processing for existing fuels refineries. In addition to crude, the import of various feedstocks, including sour VGO, sweet VGO, Atmospheric Residue, Methanol (for MTBE production), ETBE (for blending in gasoline) and NGL's are modelled.

For each process unit, utility consumption data including fuel, power, cooling water, and chemicals/catalyst use has been incorporated, which were estimated using S&P Global's internal operating cost models. Individual intermediate product stream routing is modelled for all technically feasible routings in addition to the conventional routing options for each of the process streams.

The below major process units are defined with Base & delta vectors to capture the change in yield concerning feed quality and operating conditions.

Table 5.2 – LP Delta Vectors for Secondary units

Unit	Delta vector for Quality/Severity
Hydrotreaters (Naphtha, Gasoline, Kerosene, Diesel, VGO and Residue) and Hydrocrackers (VGO and Residue)	Sulphur
Semi Regen Reformer & CCR	Octane Severity – 96,98,102 Quality – N+2A
FCC/RFCC	Sulphur, CCR,
Coker	CCR

Source: S&P Global Commodity Insights

5.2 LP Model input data and methodology

This section presents the main assumptions that are most likely to affect the LP modelling results

5.2.1 Proxy Crude slates

Crude slates at most refineries usually comprises many different crudes being processed which may be sourced both from domestic production as well as imports from other countries. The crude diet fed to a refinery is typically optimized considering the prevalent market conditions and refinery configuration to maximize the refinery gross margin.

Our analysis of historical crude slates for the EU+ refineries is based on a combination of market intelligence, judgment, and data on crude flows from historical trade data. S&P Global also factors in the technical capabilities and connectivity of refineries and leverages other organizations such as the International Energy Agency (IEA) to gain insights into historical crude slates and identify past trends and patterns.

Our crude slate forecast methodology is designed to encompass the dynamic shifts within the global oil market, accounting for factors such as evolving geopolitical events that may significantly influence trade flows. By aligning our forecasts with our Annual Strategic Workbook crude trade flows, we ensure that our projections accurately reflect the expected changes in crude oil availability. This approach enables us to estimate future crude slates, considering variables such as refinery configurations, processing capabilities, and market dynamics.

Our methodologies are continuously reviewed and updated to incorporate the latest information and insights, ensuring the accuracy and relevance of our analysis. S&P Global maintains an extensive database containing details on crude oil production, imports, exports, and refinery-specific crude slates within the study's scope. It would not be feasible to identify every crude oil processed by all the European refineries and build this into both an EU+ combined and individual refinery LPs. Leveraging this database, we derived an initial 'Long List,' to represent most of the crude by volume to be processed in 2030 by the region.

Table 5.3 – Crude processed in the EU+ region, 2030

Long List: Crude streams processed in EU+				
Crude stream	**Country of Origin**	**API**	**Sulphur (wt.%)**	**Vol %**
WTI	US	40.80	0.34	15.26%
Saharan Blend	Algeria	46.40	0.09	11.54%
CPC Blend	Kazakhstan	45.80	0.62	9.41%
Ekofisk	North Europe	41.10	0.18	8.31%
Basrah Light	Iraq	29.90	3.21	7.30%
Forties Blend	North Europe	41.20	0.58	6.17%
Grane	North Europe	28.40	0.65	6.00%
Bonny light	Nigeria	34.50	0.14	4.62%
Azeri Light	Azerbaijan	35.90	0.15	4.26%
Forcados Blend	Nigeria	32.30	0.22	3.92%
Lula	Brazil	30.70	0.35	3.48%
Arabian light	Saudi Arabia	33.90	1.91	2.80%
Western Desert	Egypt	41.70	0.42	2.78%
Troll	North Europe	36.10	0.17	2.53%
Ural	Russia	30.70	1.60	1.35%
Basrah Heavy	Iraq	24.00	4.10	1.25%
Maya	Mexico	21.60	3.46	1.13%
Kirkuk	Iraq	37.10	1.90	1.06%
Eagle Ford	US	47.10	0.08	0.88%
Arab XL	Saudi Arabia	41.00	0.91	0.79%
Merey	Venezuela	15.90	2.50	0.77%
Arab Heavy	Saudi Arabia	28.50	2.94	0.75%
Dalia	Angola	23.30	0.51	0.72%
Eagle Ford Condensate	US	60.40	0.02	0.64%
Marlim	Brazil	20.20	0.62	0.56%
Agbami-Ekoli	Nigeria	48.30	0.04	0.30%

Long List: Crude streams processed in EU+				
Crude stream	**Country of Origin**	**API**	**Sulphur (wt.%)**	**Vol %**
White Rose	Canada	31.70	0.25	0.22%
Doba	Chad	21.00	0.10	0.20%
N kossa	Congo	39.70	0.06	0.18%
Cold Lake	Canada	21.10	3.48	0.16%
Isthmus	Mexico	33.20	1.22	0.14%
Es Sider	Libya	36.70	0.37	0.09%
Vasconia	Colombia	24.30	1.08	0.08%
HLS	US	32.30	0.41	0.07%
Dar Blend	Sudan	28.40	0.09	0.07%
Iranian Light	Iran	33.50	1.45	0.06%
WTS	US	32.40	1.67	0.04%
Marib Light	Yemen	45.10	0.13	0.04%
Belayim Blend	Egypt	23.60	2.68	0.03%
Upper Zakum	Abu Dhabi	33.80	1.79	0.02%
Iranian Heavy	Iran	30.90	1.72	0.02%
Arab Medium	Saudi Arabia	31.10	2.51	0.01%
Crude & Condensate Avg. quality		**37.88**	**0.75**	**100.00%**

Source: S&P Global Commodity Insights (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate)

This “Long-List” is then condensed to a ‘Short List’ by assigning a comparable proxy crude stream based on API and Sulfur, to each crude stream identified in the “Long List”. These proxy crude grades are chosen based on the grades that constitute the dominant proportion of the total diet in the region. By this exercise, the number of crudes is reduced to 25 grades to be used in PIMS models.

The objective of this exercise is to minimize the number of crude grades to be modelled for the region without causing a significant impact on the accuracy of representing the EU+ region's overall crude mix.

The current geopolitical situation of the Russia-Ukraine conflict has significantly impacted the crude diet of European refiners, with the percentage of Russian crude in Europe's diet decreasing from approximately 20% prior to the conflict down to 1.35% at present.

The final proxy crude diet or the ‘Short List’, derived through the above exercise, is tabulated below.

Table 5.4 – Proxy Crude Slate for EU+ region, 2030

Shortlist: Crude streams processed in EU+				
Crude stream	**Country of Origin**	**API**	**Sulphur (wt.%)**	**Vol%**
WTI	US	40.80	0.34	15.44%
Saharan Blend	Algeria	46.40	0.09	11.54%
CPC Blend	Kazakhstan	45.80	0.62	9.41%
Ekofisk	North Europe	41.10	0.18	8.40%
Basrah Light	Iraq	29.90	3.21	7.34%
Forties Blend	North Europe	41.20	0.58	6.17%
Grane	North Europe	28.40	0.65	6.00%
Bonny light	Nigeria	34.50	0.14	4.62%
Azeri Light	Azerbaijan	35.90	0.15	4.26%
Forcados Blend	Nigeria	32.30	0.22	4.21%
Lula	Brazil	30.70	0.35	3.56%
Arabian light	Saudi Arabia	33.90	1.91	3.04%
Western Desert	Egypt	41.70	0.42	2.78%
Troll	North Europe	36.10	0.17	2.61%
Marlim	Brazil	20.20	0.62	1.47%
Ural	Russia	30.70	1.60	1.35%
Basrah Heavy	Iraq	24.00	4.10	1.25%
Eagle Ford	US	47.10	0.08	1.22%
Maya	Mexico	21.60	3.46	1.13%
Kirkuk	Iraq	37.10	1.90	1.06%
Arab Heavy	Saudi Arabia	28.50	2.94	0.93%
Arab XL	Saudi Arabia	41.00	0.91	0.79%
Merey	Venezuela	15.90	2.50	0.77%
Eagle Ford Condensate	US	60.40	0.02	0.64%
Arab Medium	Saudi Arabia	31.10	2.51	0.01%
Crude & Condensate Avg. quality		**37.89**	**0.75**	**100.00%**

Source: S&P Global Commodity Insights (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate)

5.2.2 Crude oil assays

For shortlisted proxy crude grades, detailed crude assays are developed using Spiral Suite's Crude Manager Software based on an internal crude database using the available assays. The assays consist of detailed information in terms of yields and relevant stream qualities for the crude oil components shown in the table below.

Table 5.5 – Crude Assay Cuts

Crude Assay Cutting Scheme	IBP (°C)	FBP (°C)
Methane	-	-125
Ethane	-125	-65
Propane	-65	-27
Isobutane	-27	-6
N-Butane	-6	14
Lt Naphtha	14	95
Heavy Naphtha	95	150
Naphtha/Kero swing cut	150	175
Lt Kerosene	175	225
Heavy Kerosene	225	260
Kero/Diesel Swing Cut	260	275
SR Diesel	260	360
Vacuum Diesel	360	370
Light VGO	370	500
Heavy VGO	500	540
VGO-VR Swing Cut	540	555
Vacuum Residue (555 °C +)	555	-
Atmospheric Residue (360 °C C+)	360	-

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate.)

Required swing cuts are added between naphtha and kerosene, kerosene and gas oil, vacuum gas oil and vacuum residue to facilitate the unit and product optimization based on unit yields and crude and product prices.

5.2.3 Crude & Feedstock supply

In establishing the crude diet for the EU+, we have anchored our approach on the shortlisted crude slate, shown in Table 5.4 with a maximum utilization rate of 86% in 2024 to meet the EU+ level target crude runs. Looking ahead to 2030, 2040, and 2050, the flexibility to optimize Crude Distillation Unit (CDU) capacity is allowed, so that the LP may allow refineries to adjust to regional supply-demand dynamics within Coastal NWE, Coastal MED, and Inland areas. This entails setting minimum CDU utilization targets of 70% in 2030, 65% in 2040, and 60% in 2050, enabling individual refineries to fine-tune operations while aligning with broader regional requirements. The maximum crude throughput is set at 86% of Installed Capacity aligning with the 2024 crude slate, and historical maximum average throughput on EU+ refineries.

Refinery feedstocks other than crude oil can be modelled in the LP model, reflecting actual refining operations. Natural gas imported by the EU refineries (as energy) is forecasted by S&P Global and is implemented as a maximum availability of natural gas in the LP model. Additionally, Straight Run Residue and Vacuum Gas Oil are imported for individual refineries to give some flexibility on running major secondary conversion units (FCC and HCK) when the CDU is at minimum practical turndown of 60% of Installed Capacity. However, maximum availability is capped at 20% of atmospheric column capacity for both Straight-run Residue and Vacuum Gas Oil.

A significant aspect of reducing carbon footprints of refinery operations and increasing the renewable content of the produced fuels leads to a shift towards renewable Hydrogen (H_2) production. In our modelling it is assumed that there is a trajectory aiming for a minimum of 50% renewable H_2 incorporation into total H_2 demand (excluding H_2 from Catalytic Reformers) by 2030, increasing to 80% renewable H_2 (excluding H_2 from Catalytic Reformers) by 2040 and a complete transition to 100% renewable H_2 (excluding H_2 from Catalytic Reformers) by 2050.

5.2.4 Process Capacity

As the first step in developing an LP model, refinery capacity data is compiled for the EU+ in terms of installed cumulative refining capacities for distillation and other process units.

S&P Global monitors refinery project announcements worldwide and adds them to the existing refinery capacity database based on projected completion dates to develop estimated future capacities. However, project announcements often tend to be optimistic, and unrealistic completion dates may be listed, resulting in many planned projects being delayed or abandoned. Therefore, S&P Global screens project announcements using a set of criteria to identify which projects are likely to be completed. These criteria include the financial strength of promoters, the status of project approval by owners or board of directors, the status of project development, the history of building similar projects, the political stability of the country, access to crude oil supply, local demand for refined products, and other key factors.

S&P Global classifies projects as either firm projects or speculative projects and includes both types in its analysis of future refinery capacity. Firm projects are those that are deemed most likely to be built, while speculative projects are those that have not yet progressed sufficiently. However, S&P Global still considers speculative projects as part of capacity going forward. The categorization of specific projects is done based on major milestones achieved or updates received through press announcements. S&P Global also keeps a close watch on announced closures of refining capacity to ensure its analysis provides comprehensive and up-to-date information. Our analysis of closures and announced capacity increases, are shown below.

Table 5.6 – Announced Capacity Closure

Refinery Rationalisation between 2024 and 2030				
Refinery	**Country**	**Owner**	**Year of closure**	**Refinery Capacity[2]**
Wesseling[1]	Germany	Shell	2025	148 KBPD
Grangemouth	United Kingdom	Petroineos	2025	145 KBPD
Livorno[3]	Italy	ENI	2024	84 KBPD
Gelsenkirchen[4]	Germany	BP	2025	85 KBPD

Source: S&P Global Commodity Insights (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate)

(1) Wesseling Refinery is part of the Shell Rheinland Refinery complex.

(2) Denoted as crude capacity, other units will also be shut down with the refinery

(3) Livorno announced it would cease operations in Feb 2024, so only prorated capacity has been used for 2024 (10 KBD)

(4) Refinery announced it would close one-third of crude processing capacity starting 2025

Table 5.7 – Announced and Speculative Capacity Additions

Firm projects capacity addition in 2030 (vs 2024)			
Owner	**Country**	**Units**	**Capacity**
Exxon Mobil Corporation	United Kingdom	Hydrotreater-Diesel	25 KBPD
Exxon Mobil Corporation	United Kingdom	Hydrogen-Steam-Methane	38 MMSCFD

Speculative projects capacity addition			
Owner	**Country**	**Units**	**Capacity**
PKN Orlen	Lithuania	Alkylation-SF	5 KBPD
PKN Orlen	Poland	CCU-Fluid	35 KBPD
BP plc	Netherlands	Hydrocracker-Distillate	70 KBPD

Source: S&P Global Commodity Insights (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate)

Capacities for each process unit type in the EU+ region were developed by aggregating individual refinery information and adding known project announcements to the existing capacity to generate future expected available capacity.

In our scenarios as the world moves towards a low carbon and eventually net-zero emissions future there will be a significant decline in demand for traditional fossil hydrocarbon fuels such as gasoline, diesel, and other related products. In our outlook we do not anticipate any new refining distillation capacity being added to the EU+ region.

The following table shows the refinery process unit capacity by technology type for the years 2024 and 2030.

Table 5.8 – EU+ Refinery Cumulative Capacity

EU+ Refinery Process Unit Capacity By Technology Type ('000 b/d except as noted)		
	EU+	EU+
Process Unit	**2024**	**2030**
Primary Separation Process		
Crude/Condensate Distillation Unit	13232	12843
Vacuum Distillation Unit	5369	5207
Conversion Process		
FCC	2128	2118
VGO Hydrocracker	1706	1611
Residue Hydrocracker	261	261
Visbreaker/Thermal Cracking	1291	1259
Coking Unit	565	554
Treatment and Enhancement Process		
Naphtha Hydrotreater	2983	2876
FCC Gasoline Hydrotreater	613	593
Kero Hydrotreater	855	810
Diesel Hydrotreater	4347	4259
VGO Hydrotreater	789	789
Resid Hydrotreater	81	81
Naphtha Isomerisation	465	464
Naphtha Reformer	1992	1915
Alkylation	293	297
MTBE	10	10
Hydrogen Generation Units[1], *MMSCFD*	2877	2834
Specialty Products Manufacturing Process		
Solvent Extraction	132	132
Asphalt	304	303
Base Oil Production[2]	114	112
Aromatics PX production (Integrated with Refinery), Mt/d	291	236

Source: S&P Global Commodity Insights (General indication of reliance on Commodity Insights analysis/data, external industry sources as appropriate)

(1) Hydrogen Generation units include steam methane reforming (SMR) and partial oxidation (POX) units

(2) Base Oil Production includes Group I, II and III and naphthenic base oils.

5.2.5 Product Slate

The table below of the Product slate is considered based on S&P Global's Annual Strategic Workbook data for LP model development and calibration.

Table 5.9 – Product Slate

Refined Products		
LPG	Sulphur	Benzene
Naphtha	Pet Coke	Mixed Xylenes
Gasoline EU VI - 95 RON EN228	Asphalt	
Gasoline Open Spec*	Renewable Jet Fuel	
Jet fuel	Renewable Diesel	
EU Diesel -10 ppm EN590	Base Oil Group I	
EU Diesel (MGO) -0.1%S	Base Oil Group II	
LSFO – 380 cSt / 0.5%S	Base Oil Group III	
HS Fuel Oil – 380 cSt / 3.5%S	Propylene	

* Primary gasoline export grade is still EU VI-95 RON. Gasoline Open Spec includes streams that cannot be blended into the 95R pool and are instead sold in export markets.

5.2.6 Pricing

The price outlooks used in the Max Electron and More Molecule Scenarios are based on S&P Global's **Green Rules** scenario.

Green Rules is intended to help our clients to consider and prepare for outcomes that deviate from the base-case scenario, Inflections. In Green Rules, the very strong public and political response to successive global crises drives governments to pursue — and successfully deliver— long-term policies and strategies that directly link national security interests with decarbonization, which complements and supports ongoing climate ambitions and goals. Over time, these forces foster robust private investment and innovation that, combined with strong shifts in consumer preferences and behavior, lead to revolutionary changes in energy use and supply and move the world much closer to the Paris Agreement on climate change targets, compared with the Inflections outlook. Key elements of the Green Rules scenario:

- **The world is more segmented and intensely competitive.** The geopolitical atmosphere is initially difficult and uncertain as nations attempt to recover from the confluence of crises of the early 2020s. Citizen demand more of their leaders and governments to take constructive action to address security threats and fears and restore general stability to domestic economic and political affairs. Although international rivalries become more intense, political lessons are learned from the near miss with great powers and leaders are pressured to manage geopolitical rivalries to prevent direct conflict and global disruption.
- **National priorities are directly linked with energy security and decarbonization.** There is a broad push across all major markets to drive down fossil energy use as fast and as extensively as possible, and to pursue clean energy technology market dominance and access to critical minerals. These goals

become central elements of national security policies and geopolitical rivalries, which eventually serve to supercharge the energy transition.

- **Governments are empowered to increase their role in energy markets and economies to secure reliable energy delivery while also accelerating the energy transition through regulations, standards, bans, mandates, incentives and investments.** These actions coincide with and intensify changes in consumer behavior and preferences that drive down energy consumption and shift energy demand patterns away from fossil fuels.
- **Sustained public demands for change support broadly successful implementation of government policies, taxes and mandates that provide powerful incentives for significant private investment in clean energy.** The combined forces of effective government and private initiatives drive a strong, sustained expansion of global investment and technology transfer that rapidly transforms the energy mix of many leading countries and sets the stage for more sustainable economic development around the world.
- **Global greenhouse gas (GHG) emissions decline steadily through 2050, but global net zero targets are not met.** The transition to a lower-GHG emissions pathway and fundamental changes in the global energy landscape come at a significant economic and human cost. People, companies, infrastructure and whole industries are made redundant, with substantial investments required to replace the old and grow the new.

5.2.6.1 Crude Oil Pricing Outlook

The oil price environment in the Green Rules scenario is primarily driven by policies to reduce oil consumption. Concentrated efforts by governments to accelerate decarbonization and slash oil demand result in market uncertainty and irregular investment, causing long cycles of falling prices followed by periods of rising prices.

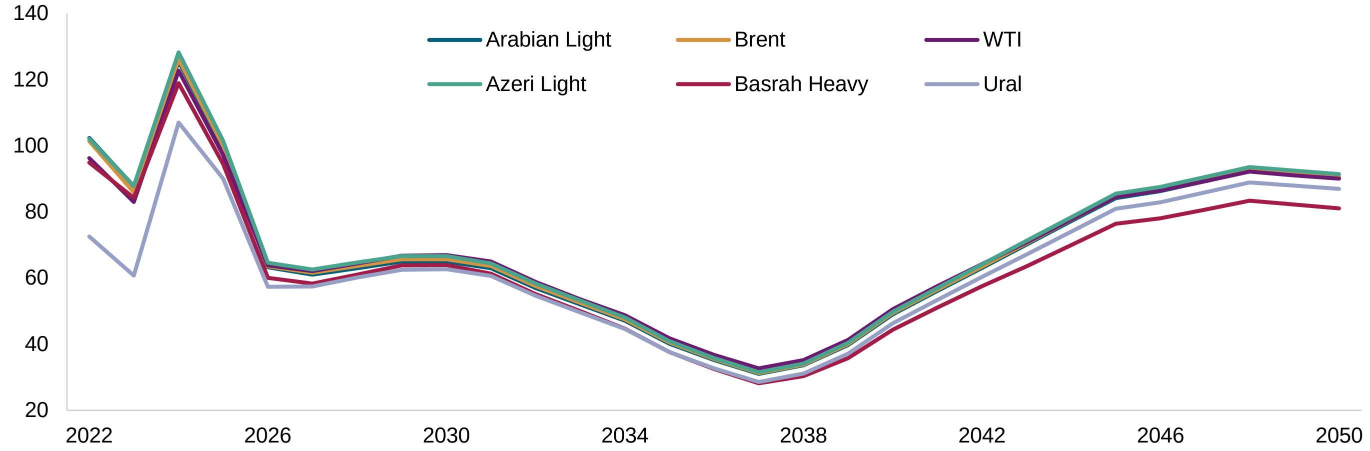
After rising briefly and modestly during the late 2020s and early 2030s, average oil prices fall sharply through the 2030s, driven by accelerating declines in the use of ICE vehicles around the world and growing competition from biofuels and hydrogen in other segments of transportation and industry. Dated Brent price peaks at $128/b in 2024 and hits a low point at $33/b in 2037 (in constant 2022 dollars). By the 2040s, many legacy assets are effectively tapped out and some new investment is needed to meet residual demand. However, given the state of the oil market, risk-adjusted investment thresholds for new projects require higher oil prices, leading to periods of tightness and rising prices to draw sufficient capital for ongoing upstream investment.

Due to declining demand for refined products, refinery margins will need to decrease in order to maintain market balance and reasonable utilization for the remaining refineries. The Green Rules policies and behavioral trends have a significant impact on gasoline demand and price. This is primarily because gasoline demand is negatively affected by the energy transition, especially due to the electrification of passenger vehicles.

However, it is worth noting that in practice, FCC margins will depend on gasoline economics and synergies between the refinery and petrochemical sector. These synergies can lead to improved profitability and operational efficiencies, which may offset some of the negative impacts on FCC margins caused by declining gasoline demand.

Green Rules naphtha prices are expected to be higher than the base case (Inflections) scenario, exceeding gasoline prices in US and Europe by the late 2030s; naphtha supply from heavily declining crude runs will be insufficient to meet demand, so the production of more on-purpose naphtha will need to be incentivized.

Figure 5.2 – Crude Price Outlook, FOB (Constant $2022 per barrel)



Source: S&P Global Commodity Insights.

5.2.6.2 Crude oils pricing methodology for LP input

Our refining economics outlook and the resulting array of regional refined product prices allow us to calculate the relative value of any crude compared to benchmark crude. each crude type, based on its natural yield of light and heavy products, which becomes a key input for projecting prices of different crude oil grades.

We project long-term Dated Brent crude prices (typically out to 25 years) on an annual average basis. Our long-term price outlooks are based on the experienced judgment of SPGCI Energy analysts, considering our outlooks on crude oil supply, demand, industry costs, geopolitics, and other factors, including full cycle finding, development, and production costs for the volumes required to meet long-term crude oil demand including replacing existing production declines.

Once the Dated Brent outlook is set, we provide outlooks for other crudes by relating the price of competing crudes via their regional refining values (quality) and the freight costs required to move each crude to market (location). In each market, the pricing of different crudes reflects the array of products that can be produced from them and the configuration of competing refineries. Our crude pricing methodology replicates these competitive market dynamics.

Using industry-available assays and our proprietary refining models, we assess the relative “refining values” of different crude oils in each regional market. The refining value of each crude oil is defined as the net dollar per barrel variable cost realization of running the crude through the region’s marginal (or “price-setting”) refinery configuration (for Europe this is an FCC cracking refinery), based on the prevailing or projected array of refined product prices. Our assessment of relative refining values of different crudes is driven mostly by our outlook for light-heavy product price differentials and by specific light product differentials.

Once we determine the relative refining values of the crudes in each market, we assume that market values will reflect relative refining values plus or minus a market premium, depending on the near-term supply-and-demand dynamics of crudes.
When market value differentials match refining value differentials, crudes are said to be in “parity.” Finally, to derive the FOB price for each assessed crude oil, we net the price back from the delivered refining market to the FOB port or pipeline node, using transportation and other logistics costs required to bring the oil to market.

FOB prices have been developed for all shortlisted crudes based on our standard crude oils pricing methodology under our Green Rules scenario. Delivered prices to either individual coastal refinery location or to known crude import terminals for inland refineries are calculated by adding freight and insurance cost to FOB crude prices. For inland refineries further transportation (Pipeline or Barge transfer) cost is added to the delivered to coastal/import terminal cost to give a refinery price based on the actual crude oil supply route.

For Coastal Refineries
Crude Oil Price = Crude Oil FOB + Shipping cost to delivery port

For Inland Refineries
Crude Oil Price = Crude Oil FOB + Shipping cost to delivery port + Pipeline Transfer Cost to individual refinery

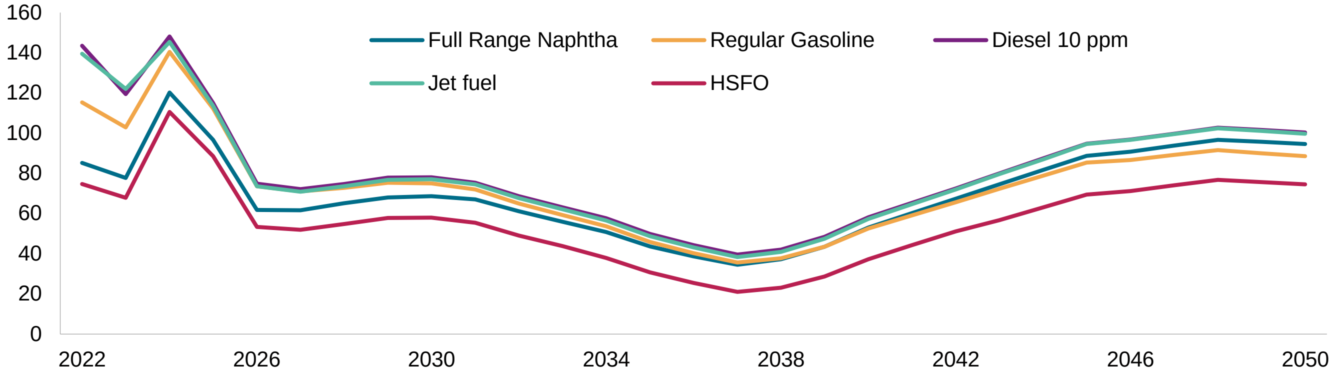
5.2.6.3 Product Price Outlook

Owing to declining refined product demand, refinery margins will need to decline sufficiently for enough refinery capacity to close to maintain market balance and reasonable utilization for remaining refineries. Thus, most benchmark net margins turn negative by the mid-2030s; surviving refineries will need to have some advantage over the typical benchmark, for example, local feed advantages or downstream integration.

In the below chart, major refined products CIF prices are plotted.

- Gasoline demand and price are the most affected by the Green Rules policies and behavioral trends.
- Naphtha prices are expected to be exceeding gasoline prices in Europe by the late 2030s in Green Rules scenario; naphtha supply from heavily declining crude runs will be insufficient to meet demand, so the production of more on-purpose naphtha will need to be incentivized.

Figure 5.3 - Refined Product Price Outlook, CIF (Constant $2022 per barrel)

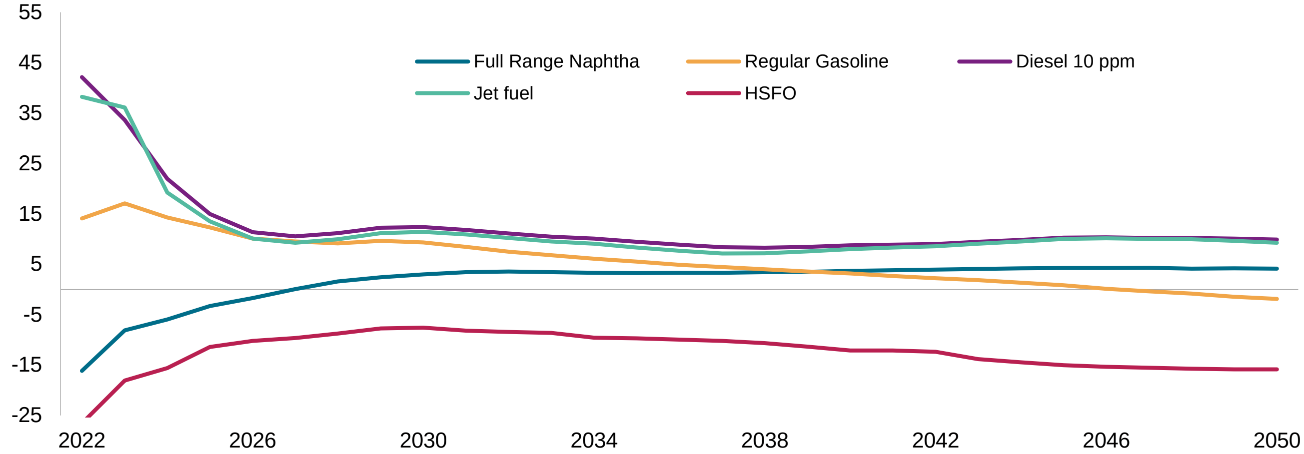


Source: S&P Global Commodity Insights.

In the below chart, products cracks in terms of differential of CIF NWE prices of the products with respect to Dated Brent FOB price is plotted.

- In Green Rules scenario, the demand for gasoline is expected to decline significantly as EVs become more prevalent, leading to a decrease in gasoline cracks. Additionally, the implementation of energy-efficient technologies and the use of biofuels will further contribute to the reduction in gasoline cracks. Ultimately, this trend is projected to result in negative gasoline cracks beyond 2045.
- Diesel cracks are anticipated to decline modestly in long-term due to truck efficiency gains. However, the overall fuel efficiency and electrification penetration will be slower and on a lower scale toward the medium/heavy duty market relative to the light-duty vehicle market. Cracks are expected to be positive throughout the forecast period.
- Jet fuel cracks closely follow the diesel cracks. However, after the mid-2030s, efficiency gains and increased consumption of SAF will temper demand growth rates and will result in some moderation in jet/kerosene cracks.
- Naphtha cracks are projected to be robust and surpass gasoline cracks in Europe by the late 2030s. This is primarily due to the inadequate supply of naphtha resulting from the significant decline in crude runs. As a result, there will be a need for naphtha value to rise sufficiently to incentivize the production of additional on-purpose naphtha, for example from hydrocrackers, to meet the growing demand.
- HSFO cracks are expected to remain in negative territory and the penetration of new alternative fuels will further contribute to push towards deeper negative territory after 2030.
- Overall cracks decline modestly in the forecast period, as refinery utilization reductions and closures keep supply and demand of refined product in balance. Cracks need to remain robust enough to support continued production of the refined products that are still required by the market.

Figure 5.4 - Refined Product Cracks, Green Rules Scenario, CIF NWE (Constant $2022 per barrel)



Source: S&P Global Commodity Insights.

5.2.6.4 Refined products pricing methodology for LP input

a. We analyze refining economics, as measured by margins, to provide a direct means of projecting specific crude oil and product price relationships (as well as to measure refining industry profitability). We use the concepts below in both our price and margin outlooks.

b. Our refining margin and light-heavy price differential outlooks set the price level for gasoline, Diesel, and heavy fuel oil relative to benchmark crudes. We evaluate margins for different regions, configurations, and operating modes.

c. Refinery profitability is driven by supply/demand pressures, and our near-term margin outlook is based on our assessment of industry utilization rates needed to meet demand changes. We set long-term margins at a level sufficient to justify investment in incremental upgrading capacity where this is required.

d. We assess refining margins on both a gross and net basis and periodically review and calibrate fixed and variable refinery operating costs and capital costs to market intelligence and gathered data.

e. Using data from the S&P Global Commodity Insights (SPGCI) Downstream Capital Costs and SPGCI Economics and Country Risk services, we develop cost outlooks for wages, chemicals, and other inputs.

f. For each key price-setting region, we determine the price-setting or marginal refinery configuration—the specific type of refinery that processes the incremental barrel of crude to meet demand. Each region has a unique set of product types with different specifications and prices, and as a result the price-setting refinery configuration differs by region. For example, the Europe price-setting refinery configuration is an FCC cracking refinery, whereas for Asia light, sour cracking refinery sets the products prices into the Singapore market and for the US Gulf Coast the price-setting refinery configuration is a light, sweet cracking refinery.

g. We assess secondary refined products (e.g., jet fuel, highway diesel, premium gasoline, low-sulfur fuel oil) using other parameters. We use incremental reforming economics to develop octane, premium gasoline, and naphtha pricing and incremental hydrotreating economics to develop prices for highway diesel and jet fuel versus diesel. These secondary relationships and forecasting techniques connect the crude and petroleum product price outlook to the SPGCI NGL and the SPGCI Chemicals price outlooks. LS Bunker (0.5 % sulphur) is our estimated price based on blending economics and/or freight.

h. The light-heavy outlook sets the price differential between light products and heavy products. Our long-term light-heavy price view is based on our outlook for incremental world oil demand, which is composed primarily of light products (gasoline, diesel, jet fuel, etc.). Since each incremental barrel of crude oil produced will need to be fully converted by the refining industry, we set our long-term light-heavy differential sufficiently wide to justify investment in additional conversion capacity (e.g., coking, hydrocracking, and catalytic cracking units).

i. Our near-term outlook (approximately one to four years) for light-heavy differentials (both crude and products) is informed by our assessment of short-term supply and demand for the heavy portion of the crude barrel.

j. Based on our stream-by-stream crude oil production outlook, we estimate the proportion of vacuum residue yield available to the market. Heavy demand is based on our estimate of gross coking capacity along with fuel oil and asphalt demand. The difference between residue supply entering the market and the capacity to directly consume or convert it provides a near-term “pressure gauge” for light-heavy margins. A surplus of vacuum residue relative to direct demand and conversion capacity will widen the light-heavy differential (and the return on refinery conversion projects) and vice versa. We project refining margins and light heavy differentials at a regional level since local factors affect regional markets. However, since the oil market is global, the supply system reacts to imbalances by shipping products or crudes inter-regionally.

k. We therefore review our outlook to ensure that our forecast interregional price differentials are consistent with projected trade and logistical costs.

5.2.6.4.1 Refined products pricing methodology for the year 2024

A. Coastal Refineries

FOB prices and CIF prices of all shortlisted products developed are based on our standard refined products pricing methodology for our Green Rules scenario at the benchmark location, Rotterdam (for NWE region) and Lavera (for MED region).

To get representative prices of refined products for individual refinery margin calculation, first the EU+ supply/demand situation is analyzed to identify the ratio of domestic demand to export for the individual products at EU+ level.

Product R1 Domestic demand to supply ratio (X) = Domestic Demand of R1/Supply of R1

Product R1 Export to supply ratio (Y) = Export of R1 /Supply of R1

These ratios will be estimated for 2030, 2040 and 2050 according to EU+ LP run outcome for each period.

i. For surplus refined products (e.g., Gasoline and Fuel Oil) pricing, a weighted sum (see table below) of CIF prices with domestic demand and FOB prices for export is applied.

Product Price = X*CIF Prices + Y*FOB Prices

Table 5.10 – Pricing Formula for Coastal Refineries (2024 – Net Surplus Products)

Products	Formula
Gasoline	= 0.35 * CIF + 0.65 * FOB
Fuel Oil	= 0.44 *CIF + 0.56 * FOB

Note: All coastal refineries will have the same ratios, irrespective of region (NWE, MED) where the refinery is located.

Source: S&P Global Commodity Insights.

ii. For deficit refined products (e.g., Diesel, Jet Fuel etc.) CIF prices at benchmark location either Rotterdam (for NWE region) or Lavera (for MED region), based on respective country's geographical location used.

Product Price = CIF Prices

Table 5.11 – Pricing Formula for Coastal Refineries (2024-Net Deficit Products)

Products	Formula
Diesel/Gasoil	= 1 * CIF
Jet/Kero	= 1 * CIF
Naphtha	= 1 * CIF
LPG	= 1 * CIF

Source: S&P Global Commodity Insights.

B. Inland Refineries

FOB prices and CIF prices of all shortlisted products developed based on our standard refined products pricing methodology for Green Rules scenario at the benchmark location, Rotterdam (for NWE region) and Lavera (for MED region).

For Domestic Consumption from Inland Refineries

a. Prices realized by the respective inland refinery for deficit products (at EU+ level) is the sum of CIF prices at benchmark location and premium (transfer cost from refinery to the nearest port which is being used for refined products trade by respective country).
Product Price = CIF Prices + Premium

b. Prices realized by the respective inland refinery for net export products (at EU+ level) is CIF prices at benchmark location (NWE or MED based on refinery location).

Product Price = CIF Prices

For Export from Inland refineries

It is anticipated that there will be no exports from the inland refineries in 2024 and that these refineries will supply all product inland to help meet domestic demand.

5.2.6.4.2 Refined Products Pricing Methodology for 2030 & 2040

FOB prices and CIF prices of all shortlisted products developed are based on our standard refined products pricing methodology for our Green Rules scenario at the benchmark location, Rotterdam (for NWE region) and Lavera (for MED region).

To derive representative prices of refined products for individual refinery margin calculations, the EU+ block is initially divided into three distinct regions: Coastal NWE, Coastal MED, and Inland Europe. Subsequently, a thorough analysis of the regional supply and demand dynamics is conducted to ascertain the proportion of domestic consumption and exports for each product within each region (Coastal NWE, Coastal MED, and Inland Europe) relative to the total supply of that product with 1st pass of LP runs.

Product R1 Domestic demand to supply ratio (X) = Domestic Demand of R1/Supply of R1

Product R1 Export to supply ratio (Y) = Export of R1 /Supply of R1

A weighted sum (see below) of CIF prices (For Coastal refineries) & CIF+ Premium (Inland region) with domestic demand and FOB prices (For Coastal refineries) & FOB- Discount (Inland region) for export is applied.

Table 5.12 - Regional Pricing Formula: Max Electron

Products	Coastal NWE		Coastal MED		Inland	
	2030	2040	2030	2040	2030	2040
Diesel/Gasoil	1*CIF	0.76CIF+0.24*FOB	1*CIF	1*CIF	1*CIF+ Premium	1*(CIF+ Premium)
Jet/Kero	1*CIF	1*CIF	1*CIF	1*CIF	1*CIF+ Premium	1*(CIF+ Premium)
Gasoline	0.67*CIF+0.33*FOB	0.66*CIF+0.34*FOB	0.62*CIF+0.38*FOB	0.57*CIF+0.43*FOB	1*CIF	1*CIF
Fuel oil	0.81*CIF+0.19*FOB	0.84*CIF+0.16*FOB	0.56*CIF+0.44*FOB	0.93*CIF+0.07*FOB	1*CIF	1*CIF
Naphtha	0.88*CIF+0.12*FOB	0.71*CIF+0.29*FOB	0.51*CIF+0.49*FOB	0.98*CIF+0.02*FOB	1*CIF	1*CIF

Source: S&P Global Commodity Insights.

Table 5.13 - Regional Pricing Formula: More Molecule

Products	Coastal NWE		Coastal MED		Inland	
	2030	2040	2030	2040	2030	2040
Diesel/Gasoil	1*CIF	0.93CIF+0.07*FOB	1*CIF	1*CIF	1*CIF+ Premium	1*(CIF+ Premium)
Jet/Kero	1*CIF	1*CIF	1*CIF	1*CIF	1*CIF+ Premium	1*(CIF+ Premium)
Gasoline	0.64*CIF+0.36*FOB	0.65*CIF+0.35*FOB	0.63*CIF+0.37*FOB	0.51*CIF+0.49*FOB	1*CIF	1*CIF
Fuel oil	0.80*CIF+0.20*FOB	0.68*CIF+0.32*FOB	0.53*CIF+0.47*FOB	0.54*CIF+0.46*FOB	1*CIF	1*CIF
Naphtha	0.87*CIF+0.13*FOB	0.71*CIF+0.29*FOB	0.55*CIF+0.45*FOB	0.82*CIF+0.18*FOB	1*CIF	1*CIF

Source: S&P Global Commodity Insights.

5.2.6.4.3 Refined products pricing methodology for the year 2050

The EU+ is projected to have a significant net surplus of fossil refined products, with very little domestic demand except for naphtha and jet fuel.

C. Coastal Refineries

1. For Naphtha & Jet, CIF prices at respective benchmark locations (NWE or MED based on refinery location) are used for the calculation of the coastal refinery margin.
2. For other refined products, FOB prices at respective benchmark locations (NWE or MED based on refinery location) are used for the calculation of coastal refinery margin.

D. Inland Refineries

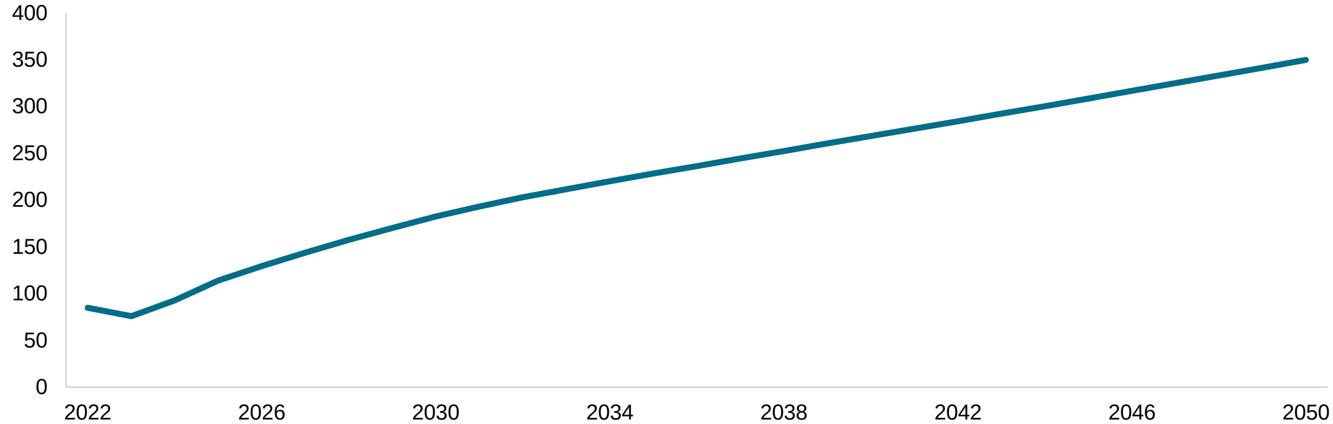
3. For Naphtha & Jet, (CIF + Premium) prices at respective benchmark locations (NWE or MED based on refinery location) are used for the calculation of the inland refinery margin.
4. For other refined products, prices realized by the respective inland refinery for net surplus products (at EU+ level) is the difference of FOB prices at benchmark location and discount (transfer cost from refinery to the nearest port which is being used for refined products trade by respective country).

Product Price = FOB Prices - Discount

5.2.6.5 Carbon pricing

From 2024 to 2050, carbon pricing in Europe undergoes a transformative journey, reflecting the EU's commitment to combat climate change. In the Green Rules scenario, beginning with an initial price of $92.55 per ton (Constant $2022) of CO_2 in 2024, carbon pricing mechanisms gain traction as vital tools for incentivizing emission reductions across industries. With the European Union's strengthened carbon market and emission reduction targets, carbon pricing becomes increasingly stringent and comprehensive, steadily rising to $350 per ton (Constant $2022) of CO2 by 2050.

Figure 5.5: Carbon price - Green Rules, (constant $2022 per metric ton)



Source: S&P Global Commodity Insights.

5.2.7 LP model limitations

This section illustrates some of the aspects that could be considered as a limitation for use of this model. This is not intended to be an exhaustive list and only to illustrate to the reader of this report that such aspects exist and should be taken into consideration.

i. Aggregated EU+, inland, NWE coastal, MED coastal refinery LP model runs are expected to over-optimize in the sense that such a model considers the entire region as a single site refinery allowing transfer of streams between units without considering the logistical constraints that exist due to refineries being in different locations.

ii. The LP Model is calibrated to match the operation of a particular single year. In general, this will hold good, to represent the regional operations at a macro-level for another reference period as long as there are no material differences in the available installed unit capacities, process technologies, global crude balances, and regional product qualities. Necessary adjustments would be made for a different reference period if the changes in these aspects of model calibration are significant.

iii. The crude grade mentioned in the proxy crude diet is not necessarily that particular crude. As the name suggests it is a proxy to simulate using that grade.

iv. In this model, we have not taken into account the local synergies that can arise from integrating petrochemical plants with refinery complexes.

v. CO_2 emissions within the LP model are determined by applying specific emission factors to each fuel stream outlined in the energy balance. Using the same LP model for evaluating individual refineries yields an emission factor (tonne CO_2/tonne throughput) per refinery, contingent upon configuration and utilization rate. However, it does not take into account differences in energy efficiency between refineries. This approach assumes uniform energy performance across all refineries and therefore this methodology will not differentiate between those refineries that are “best in class” in energy performance and those that are poor in energy performance.

vi. These models represent conventional refinery operations as they are performed in the refining industry to meet product specifications. For this study, non-conventional blending streams of kerosene, diesel, and gasoline are used, with qualities approximated using publicly available data. These blending qualities are assumed uniform across all refineries.

5.3 Refinery Margin Calculation and Rationalization Methodology

Refineries are essential for converting crude oil into various products, but their long-term sustainability can be significantly impacted by economic factors. Refinery margins measure the value a refinery adds per unit of input, typically assessed per barrel of crude oil processed. Negative margins indicate that the cost of refining crude oil exceeds the value obtained from selling the refined products.
The gross refining margin (GRM) is calculated by subtracting the cost of crude oil from the revenue generated by selling the refined products. This is the starting point for determining the net margin. The net variable margin is obtained by subtracting the variable costs, such as catalyst and chemical costs, water costs, and power costs, from the GRM.

To calculate the net margin from the net variable margin, fixed operating costs and carbon tax are taken into account.

- Fixed operating costs include labor charges, maintenance charges, insurance and taxes, and general & administrative charges. Refineries incur expenses for routine maintenance, insurance & taxes. These charges are calculated as a percentage of the refinery's replacement cost. Labor cost is estimated based on the refinery unit type and localized labor rates. While general and administrative costs are estimated based on a percentage of the refinery capacity.

  Initially, we obtain nominal net variable margins from the LP Model for various years (e.g., 2024, 2030, 2040, and 2050). To ensure consistent comparison, we convert these nominal margins into real 2022 dollars values using inflation index. After this conversion, we subtract the fixed costs associated with refinery operations to obtain net cash margin. This step provides a clearer picture of net cash margins, accounting for both price changes and operational expenses.

- Carbon cost is calculated based on scope 1 & 2 CO_2 emissions[6] from the LP model output for the individual refinery and green case scenario carbon prices by using formula given below:

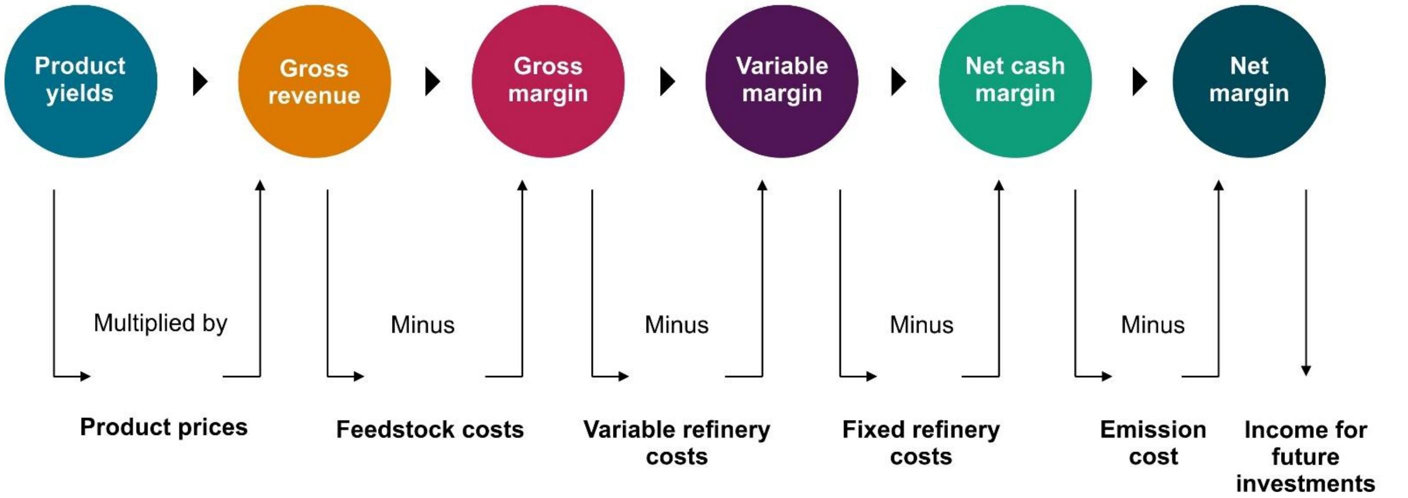
  Carbon cost = Total scope 1 & 2 emissions of individual refinery x Carbon Price

[6] All LP runs share the same utility consumption and emission vectors, so net margin doesn't reflect individual refinery's energy efficiency.

For 2024 and 2030, Carbon cost is calculated after deducting free emissions allowance which is set using the average of top 10% performance (benchmark CO2/CWT[7]) in terms of emissions per CWT[8]. For 2040 and 2050, Carbon cost is calculated considering refiners pay all their CO2 emissions costs but get carbon cost recovery from the products which are sold inland.

Subtracting these fixed operating costs and carbon tax from the net variable margin yields the net margin. Refineries which are operating in negative net margins are considered for rationalization.

Figure 5.6: Refinery margin calculations



5.4 Model Outputs: Detailed Results and Implications

In this section, we present and analyze the outputs generated by our LP model. The results obtained from the LP model provide critical insights into future refining operations for EU+ under both the More Molecule and max electron scenarios. We will examine the key findings, interpret the significance of the data, and discuss the implications of these results.

For the LP model run, we have considered a minimum 60% turndown operation for major processing units, including Crude and Vacuum Distillation, Fluid Cracking Unit, VGO Hydrocracker, and reformer units. This ensures that the model captures the potential operational flexibility and limitations of these units in response to changing market conditions.

It is important to note that in this exercise, we are assessing the business as usual of conventional fossil fuel refineries. We have not considered the potential financial performance improvement if these sites shift into bio-refineries.

[7] For 2024, the Benchmark is taken as 0.0228 tCO2e/CWT and for 2030, the Benchmark is considered 0.0206 tCO2e/CWT considering cut by 7.5% as NIMs exercise to be started for the year 2026-30.

[8] CWT for refineries is calculated based on methodology as per Concawe report 09/12 (Developing a methodology for an EU refining industry CO2 emissions benchmark).

5.4.1 Max Electron Scenario

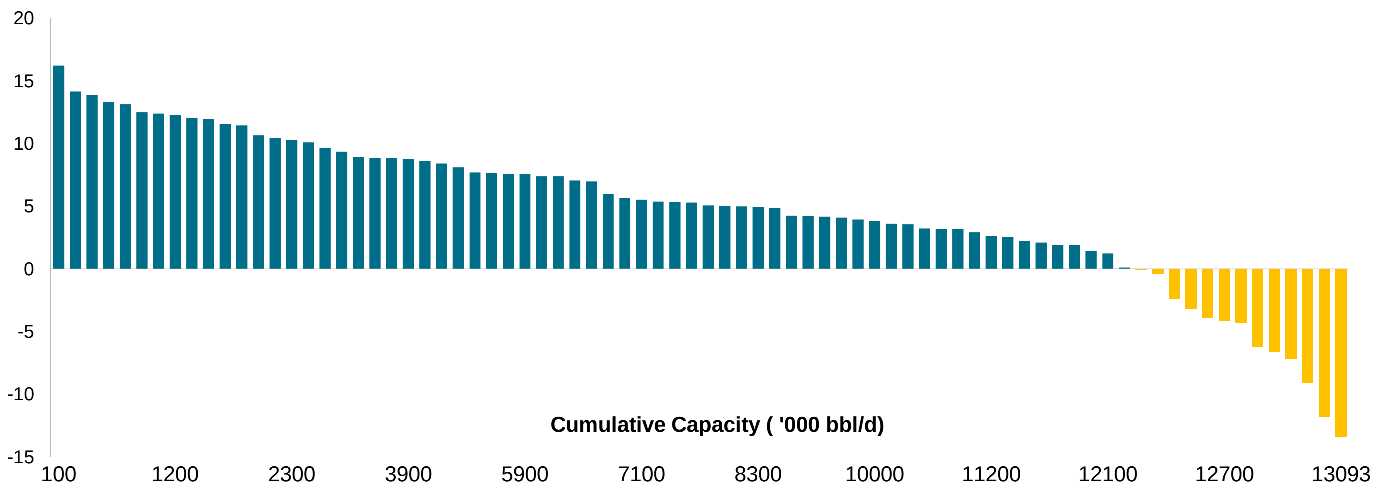
The following chapter summarizes key outputs from the LP model regarding net margin, refinery capacity utilization, and the EU+ supply-demand balance for the years 2024, 2030, 2040, and 2050 under the Max Electron scenario.

5.4.1.1 Net Margin: Max Electron Scenario

The net margin for each operating refinery was determined using the net variable margin generated by the LP PIMS model. Additionally, a comprehensive forecast curve was created for the net margin for both year 2024 and 2030. According to the expected net margin curve, shown in Figure 5.7 below, a total of 13 out of the 78 refineries have a negative net margin in 2024, equivalent to approximately 0.87 million barrels per day (MBPD) of crude distillation capacity.

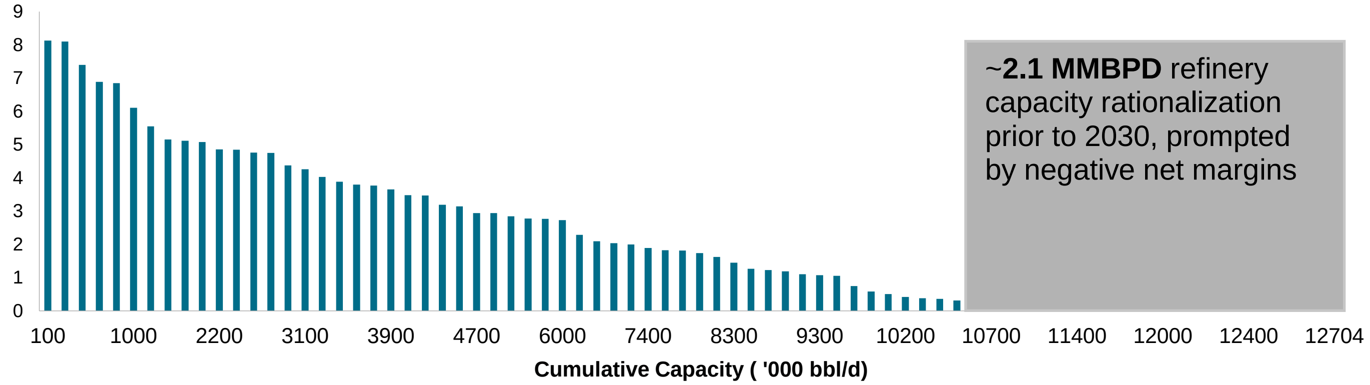
The average net margin of top 5 refineries in 2024 is 14.1 $/b, while in 2030 it drops to 7.5 $/b in real 2022 $ basis. Refineries are expected to face pressure for capacity rationalization due to this significant drop in net margins. Between 2024 and 2030, 22 refineries equivalent to 2.1 MMBPD are expected to rationalize owing to negative net margins. These refineries face challenges in generating positive net margins as various factors, including changing market dynamics, evolving regulatory requirements and EU+ energy transition efforts, efficiency gains and fleet electrification, lead to a decline in domestic demand.

Figure 5.7: Net margin Forecast 2024 (Constant 2022$/b) - Max Electron



Margins include emission costs
Source: S&P Global Commodity Insights.

Figure 5.8: Net margin Forecast 2030 (Constant 2022$/b) - Max Electron



Margins include emission cost
Source: S&P Global Commodity Insights.
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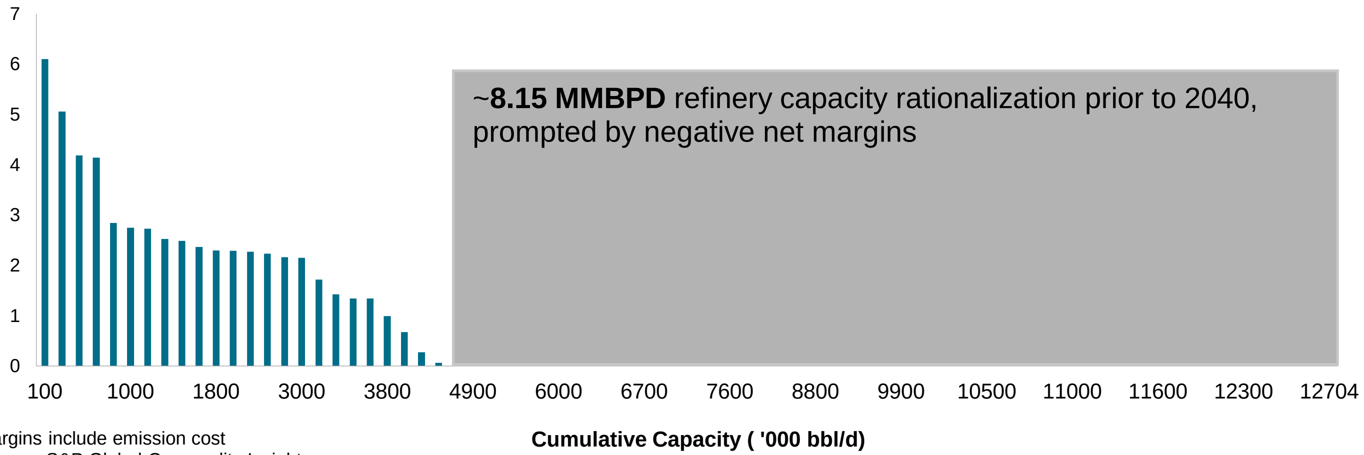
The transition from fossil fuels to more sustainable alternatives accelerates, resulting in a rapid decline in demand of refined products. Consequently, the traditional refining industry faces falling margins, leading to the rationalization of 64% of 2024's total installed refining capacity by 2040.

Figure 5.9: Net margin Forecast 2040 (Constant 2022$/b) - Max Electron



Margins include emission cost
Source: S&P Global Commodity Insights.
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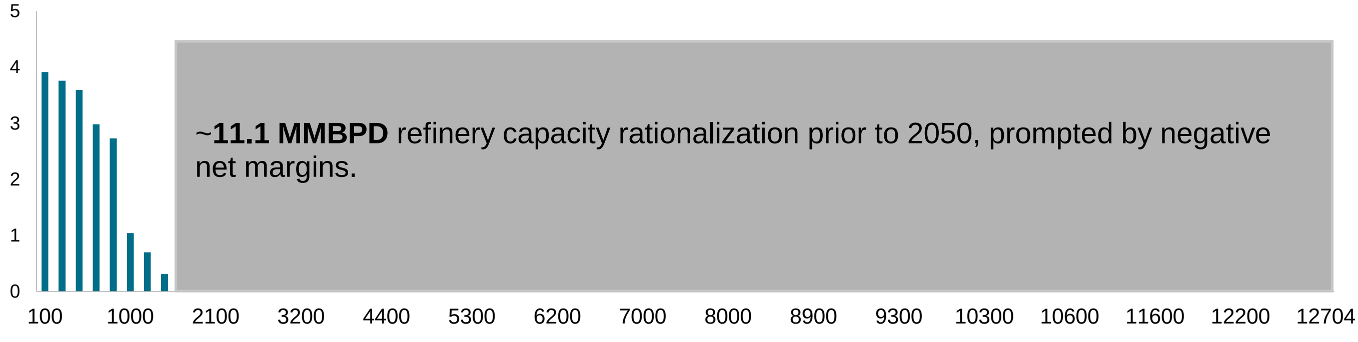
At the end of our forecast period, it is expected that only 8 refineries, equivalent to 12% of the total installed capacity in 2024, will continue operating with a positive net margin. The remaining refineries are expected to be rationalized or closed over the period 2024-2050.

Figure 5.10: Net margin Forecast 2050 (Constant 2022$/b): Max Electron

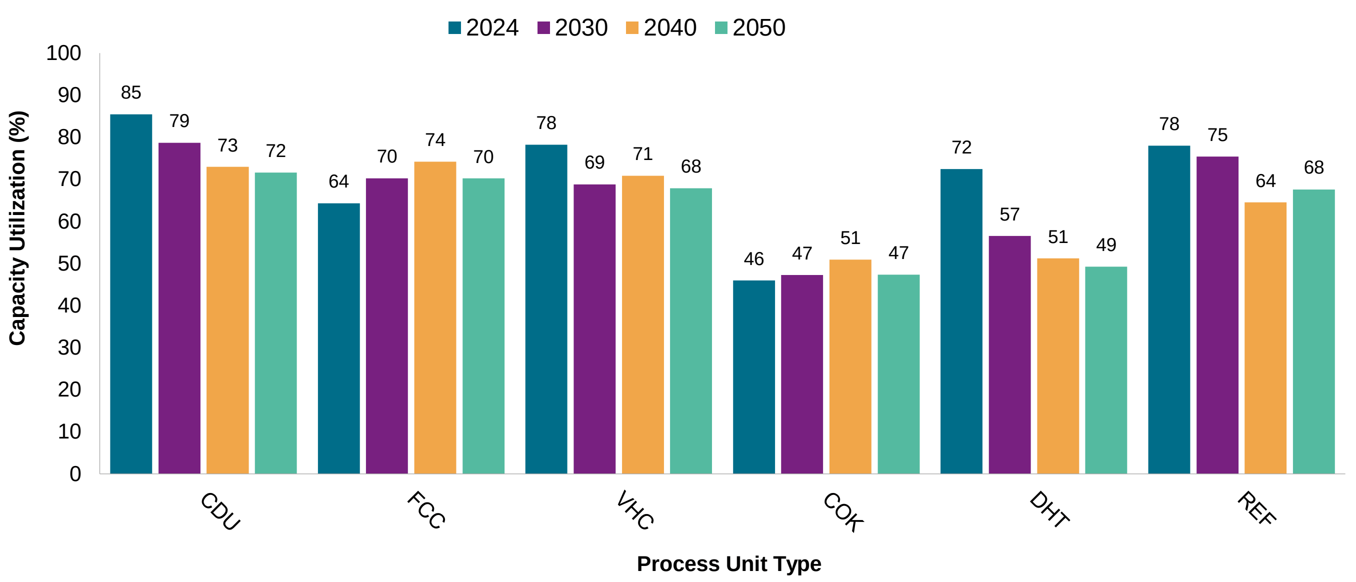


Margins include emission cost
Source: S&P Global Commodity Insights.

5.4.1.2 Refining Capacity Utilization

In the Max Electron scenario, the adoption of e-mobility in EU+ is poised to significantly impact the oil demand of this region. As oil demand declines, there will be less need for refining capacity, and this can be observed in Figure 5.11. Refineries must adapt to this changing landscape by aligning their utilization capacity with market demand. The projected trend indicates a significant decrease in CDU capacity utilization. Estimates suggest a decline from an average of 85% in 2024 to 79% in 2030, further dropping to 73% in 2040, and eventually reaching 72% by 2050, based on the limited remaining capacity after rationalization. This indicates a significant reduction in operational capacity over time.

Figure 5.11 - Capacity Utilization: Max Electron



Source: S&P Global Commodity Insights.

CDU = Crude Distillation Unit, FCC = Fluid Catalytic Cracker, VHC = VGO Hydrocracker, COK = Coking, DHT= Diesel Hydrotreater, REF = Reformer

Please refer Table 5.14 for detailed information on the installed capacity available in remaining refineries after rationalization, categorized by technology type, along the timeline (2024, 2030, 2040 and 2050).

Table 5.14: Process units installed capacity in specified years after refinery rationalization - Max Electron

Max Electron EU+ refinery process unit capacity by technology type				
('000 b/d except as noted)				
	EU+	**EU+**	**EU+**	**EU+**
Process unit	**2024**	**2030**	**2040**	**2050**
Primary separation process				
Crude/condensate distillation unit	13,232	10,793	4,691	1,718
Vacuum distillation unit	5,369	4,574	1,916	744
Conversion process				
FCC	2,128	1,847	778	183
VGO hydrocracker	1,706	1,476	732	339
Residue hydrocracker	261	151	29	0
Visbreaker/thermal cracking	1,291	1,082	390	146
Coking unit	565	506	337	182
Treatment and enhancement process				
Naphtha hydrotreater	2,983	2,499	972	254
FCC gasoline hydrotreater	613	522	315	146
Kero hydrotreater	855	709	257	112
Diesel hydrotreater	4,347	3,660	1,733	714
VGO hydrotreater	789	666	80	15
Resid hydrotreater	81	81	0	0
Naphtha isomerisation	465	362	140	36
Naphtha reformer	1,992	1,642	719	264
Alkylation	293	264	124	24
MTBE	10	8	2	1
Hydrogen generation units[1], *MMSCFD*	2,877	2,329	1,024	512
Specialties products manufacturing process				
Solvent extraction	132	132	32	0
Asphalt	304	229	76	28
Base oil production[2]	114	108	47	31
Aromatics PX production (integrated with refinery), Mt/d	291	234	161	117

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data and external industry sources as appropriate.)

(1) Hydrogen generation units include SMR and POX units.

(2) Base oil production includes group I, II and III and naphthenic base oils.

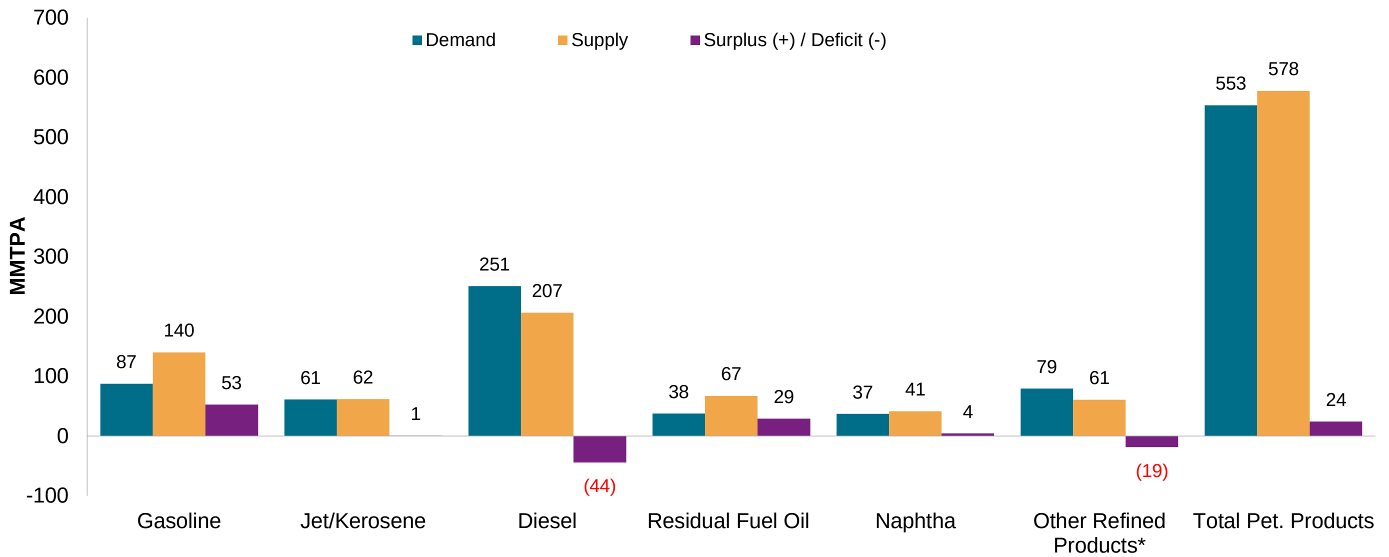
Refineries are expected to explore low-carbon hydrogen options to align with sustainability goals. This is observed in the LP model output results, which project a significant drop in hydrogen manufacturing unit capacity utilization from the 2024 level. This shift in hydrogen space will be primarily driven by reduction in overall refining capacity utilization and secondly, replacement of grey hydrogen by green hydrogen as due to technological advancement, large scale production cost of green hydrogen is projected to drop significantly. We have assumed on-purpose Hydrogen production through SMR (Steam Methane Reforming) will be replaced by green hydrogen by 50% in 2030 and 100% in 2050.

5.4.1.3 EU+ Refined products balances

In the Max Electron scenario, growth in demand for refined products is expected to decelerate in the long term, as policy-driven changes, particularly around EVs and mobility, spur the energy transition. Electric and hybrid vehicles are expected to make rapid inroads in the mid to long term in EU+ market, dampening liquid fuel demand significantly by 2050 in comparison to the 2024 level. The decline in fuel demand is also expected to change the net trade position of fossil refined products in the EU+ region.

In 2024, the EU+ region is projected to have a notable net surplus of important refined products, including gasoline and residual fuel oil. Nevertheless, the region is still expected to face a deficit of 18% in diesel demand, with diesel accounting for about 45% of total refined products demand.

Figure 5.12: Refined Products Demand vs Supply (2024) - Max Electron

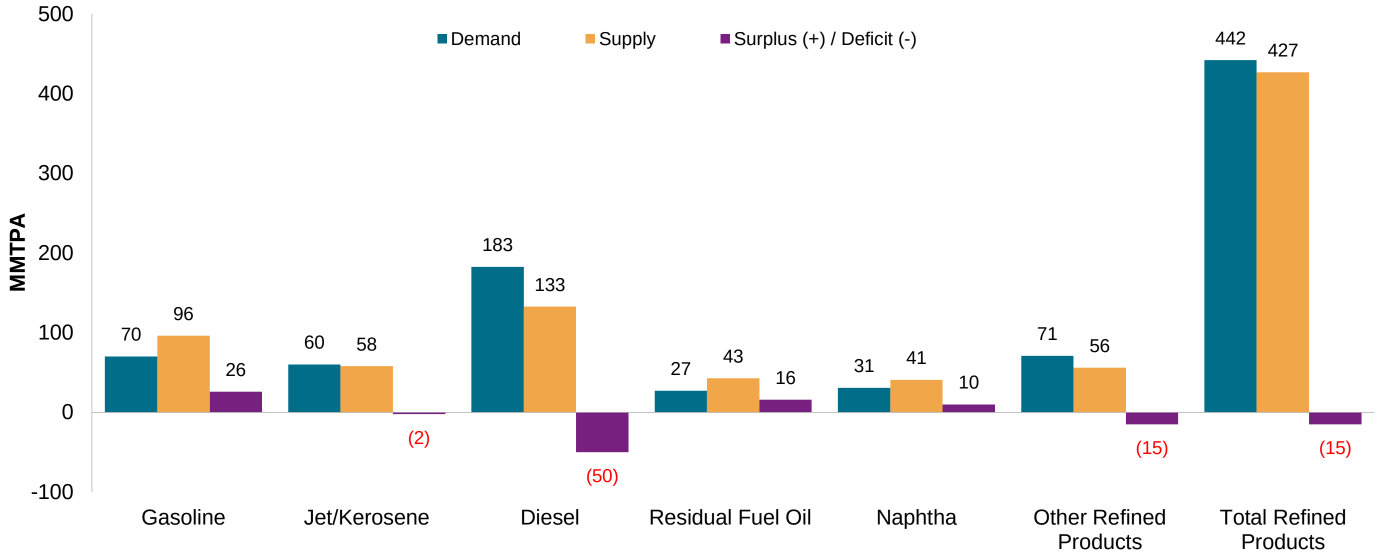


Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

By 2030, Europe is expected to have a surplus in gasoline and fuel oil but will experience a deficit in diesel. Overall, the demand for refined products is projected to drop by 20% compared to 2024, resulting in a lower trade volume. Furthermore, initiatives for energy transition, improvements in efficiency, and the electrification of light-duty vehicles are likely to reduce road diesel's share of total product consumption to 41% in 2030 and further down to 27% by 2040. By 2040, capacity rationalization due to negative net margins leads to decreased production capacity, necessitating increased reliance on imports for refined products, especially for Jet/kerosene and “Other” refined products.

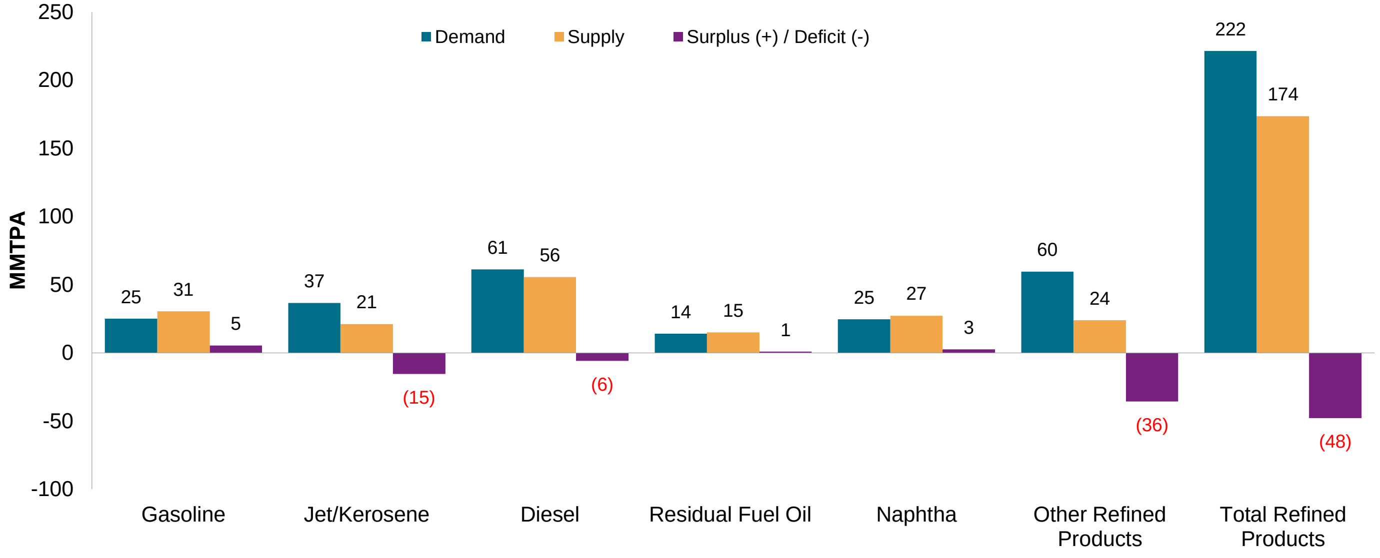
Figure 5.13: Refined Products Demand vs Supply (2030) - Max Electron



Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

Figure 5.14: Refined Products Demand vs Supply (2040) - Max Electron



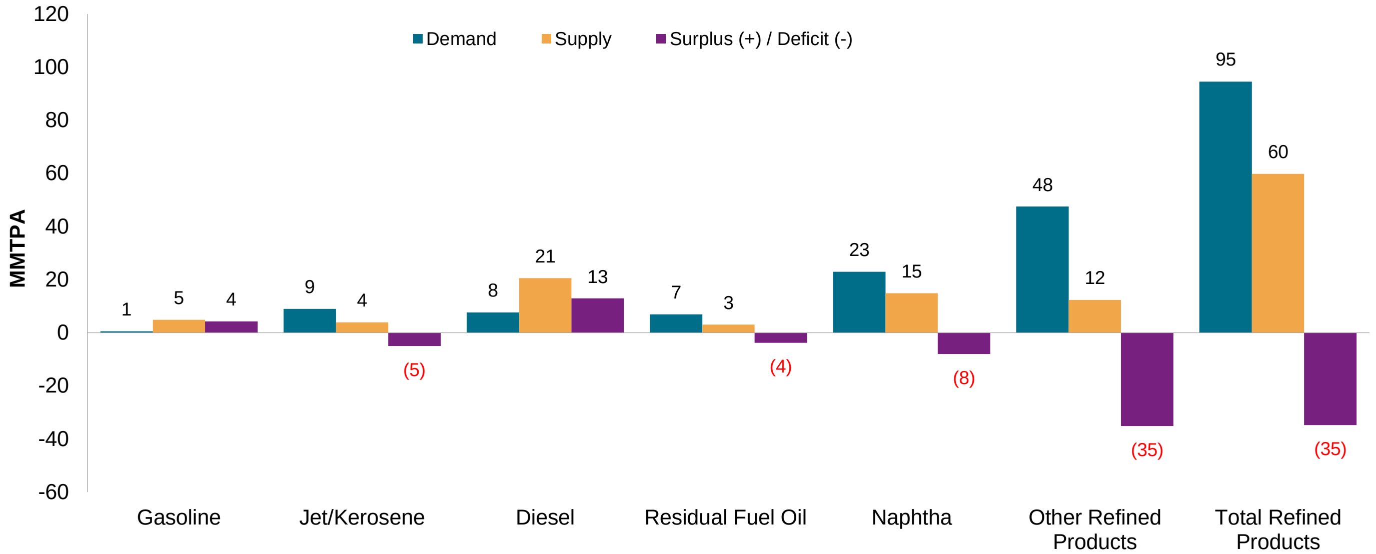
Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

Fast forward to 2050, due to further refining capacity rationalization, the EU+ is expected to be in deficit of refined petroleum products. Fossil naphtha is anticipated to be in deficit in the EU+ by 8 million metric tons per annum (MMTPA) despite the supply of bio naphtha increasing to help meet the demand of the petrochemical sector.

By 2050, a decline in demand for refined products is expected. In this increasingly competitive landscape, high conversion refineries are likely to operate, resulting in a reduction in fuel oil production. Despite lower demand, the EU+ is set to face a deficit in residual fuel oil. The significant drop in fossil diesel demand, from 61 million metric tons per annum (MMTPA) in 2040 to approximately 8 MMTPA in 2050, will allow the EU+ to achieve a surplus in fossil diesel. “Other” refined products will hold a significant 50% of the total refined products demand in 2050. Within this category, asphalt will hold the largest demand share of 25%. However, due to significant refinery rationalization post 2035, the supply of asphalt is expected to decrease to only 1.9 MMTPA in 2050.

Figure 5.15: Refined Products Demand vs Supply (2050) - Max Electron



Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

5.4.2 More Molecule scenario

The following chapter summarizes key outputs from the LP model regarding net margin, refinery capacity utilization, and the EU+ supply-demand balance for the years 2024, 2030, 2040, and 2050 under the More Molecule scenario.

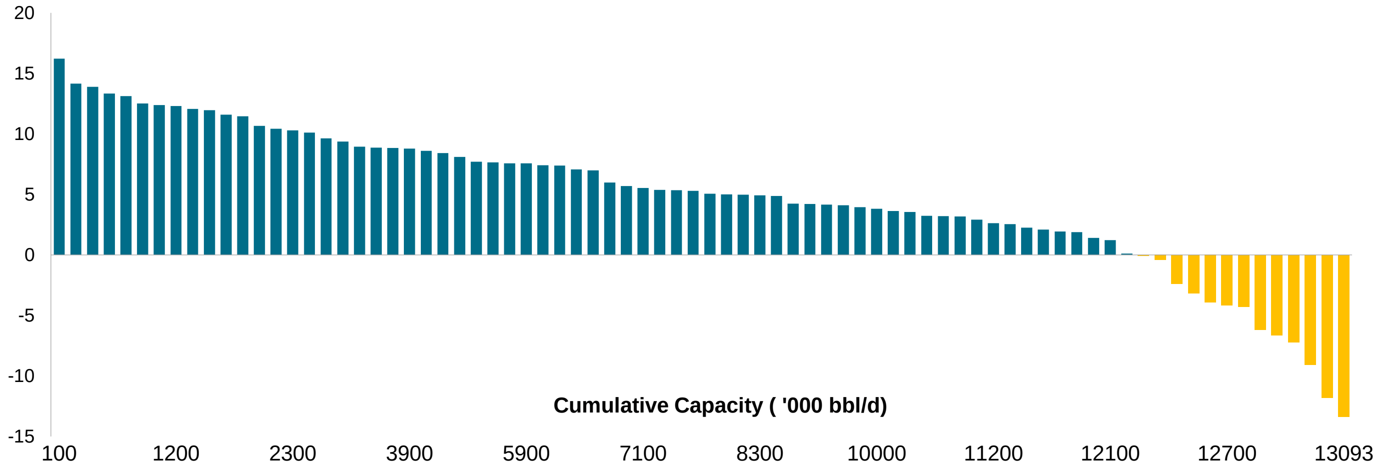
5.4.2.1 Net margin: More Molecule Scenario

According to the projected net margin curve, shown in

Figure 5.16 below, in this scenario a total of 13 out of the 78 refineries will have negative net margins in 2024, equivalent to approximately 0.87 MMBPD capacity.

The average net margin of top 5 refineries in 2024 is 14.1 $/b, while in 2030 it drops to 6.7 $/b in constant 2022 $ basis. In this scenario also, refineries are indeed expected to face pressure for capacity rationalization due to this significant drop in net margins. Between 2024 and 2030, 21 refineries equivalent to 1.8 MMBPD are expected to rationalize owing negative net margins. Refineries are expected to encounter difficulties in achieving positive net margins due to factors such as energy transition initiatives in the EU and beyond, efficiency improvements, the shift toward electric fleets, reducing domestic demand, and low export opportunities resulting from capacity expansions in other regions.

Figure 5.16: Net margin Forecast 2024 (Constant 2022$/b) - More Molecule



Margins include emission costs
Source: S&P Global Commodity Insights.
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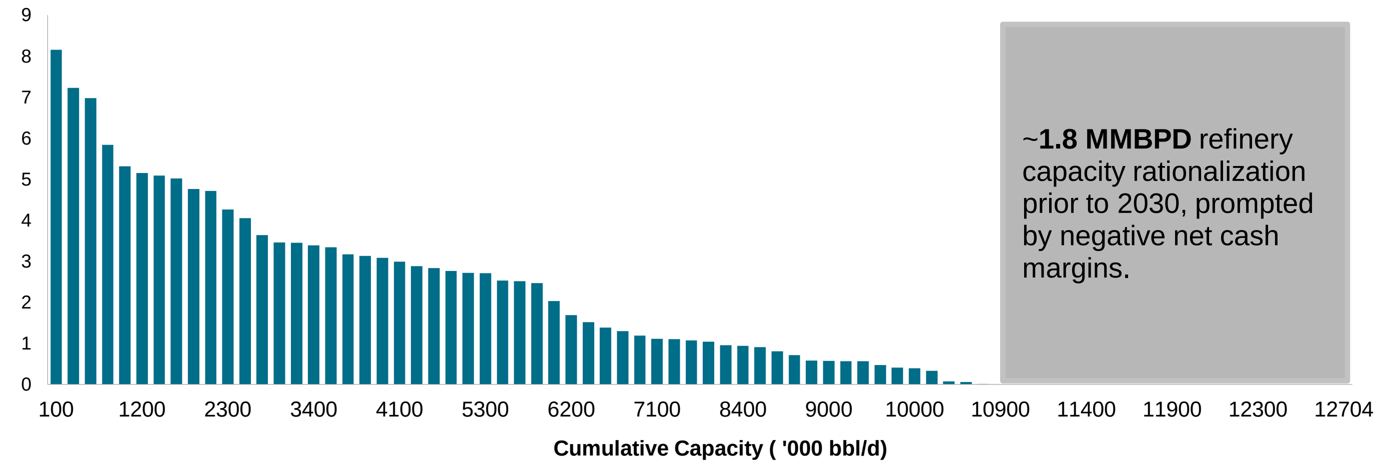
Figure 5.17: Net margin Forecast 2030 (Constant 2022$/b) - More Molecule



Margins include emission costs
Source: S&P Global Commodity Insights.
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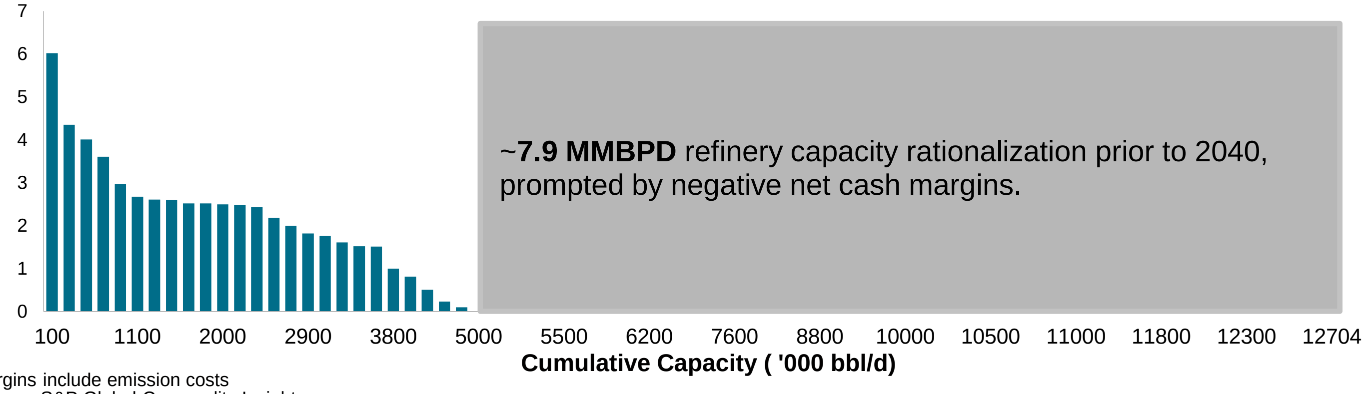
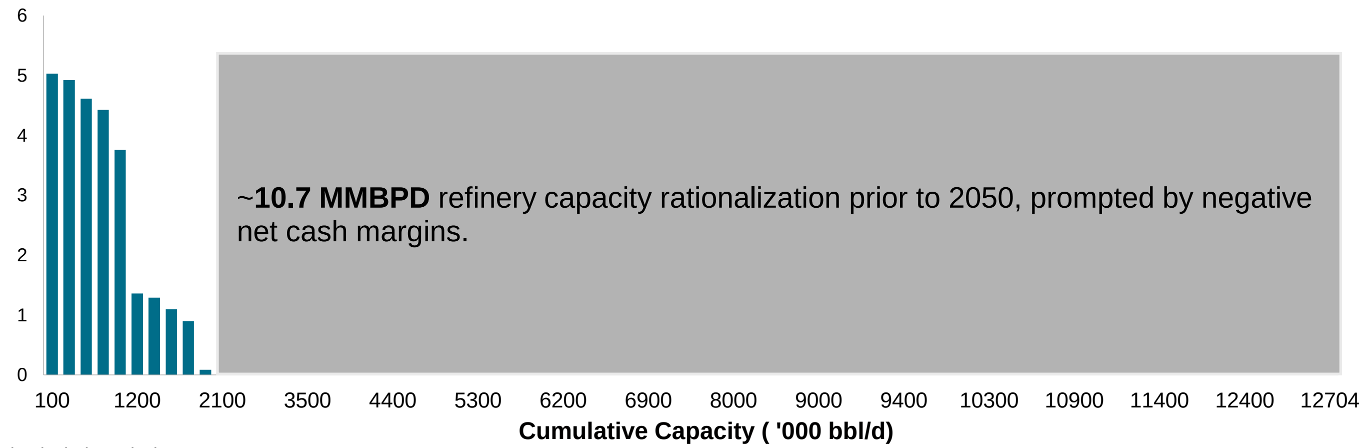
Based on the forecast curve for net margin, in this scenario 51 out of 76 refineries have negative margins in 2040, equivalent to approximately 7.9 MMBPD capacity. By 2050, 66 refineries have negative margins, and this corresponds to roughly 10.7 MMBPD of capacity, out of a total 2024 installed capacity of 12.7 MMBPD.

Figure 5.18: Net margin Forecast 2040 (Constant 2022$) - More Molecule



Margins include emission costs
Source: S&P Global Commodity Insights.

Figure 5.19: Net margin Forecast 2050 (Constant 2022$) - More Molecule

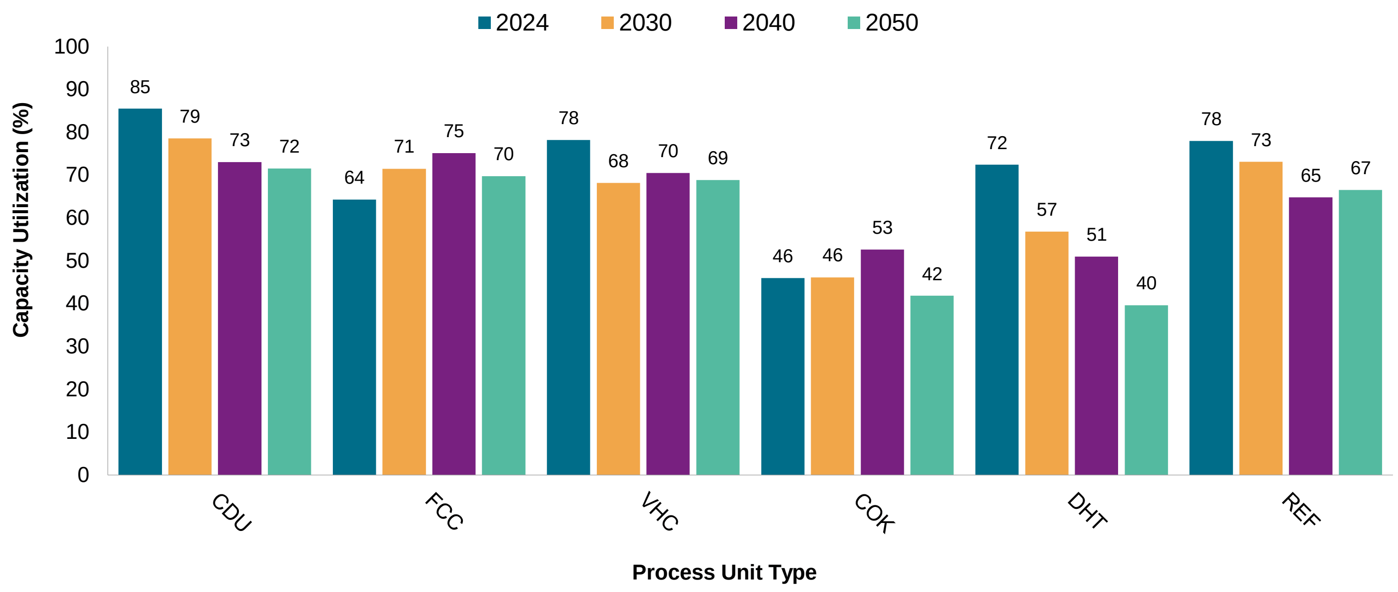


Margins include emission costs
Source: S&P Global Commodity Insights.

5.4.2.2 Refining Capacity Utilization

More Molecule scenario push for the adoption of green fuels in EU+ is poised to significantly impact the fossil fuel demand in the region. As fossil fuel demand declines, the need for traditional refining capacity will decrease (see Figure 5.20). Refineries must adapt to this shift from the grey to green molecule by aligning their utilization capacity with market demand. The projected trend indicates a substantial decrease in capacity utilization, with estimates suggesting a decline from an average of 85% in 2024 to 79% in 2030, further dropping to 73% in 2040, and eventually reaching 72% by 2050, despite the significant refinery rationalization. As in the Max Electron scenario, refineries will increasingly explore low-carbon hydrogen options to align with sustainability goals. Refiners will transition to green hydrogen, thereby reducing the utilization of existing grey hydrogen production capacities.

Figure 5.20: Capacity Utilization - More Molecule



Source: S&P Global Commodity Insights.

CDU = Crude Distillation Unit, FCC = Fluid Catalytic Cracker, VHC = VGO Hydrocracker, COK = Coking, DHT= Diesel Hydrotreater, REF = Reformer

Please refer to Table 5.15 for detailed information on the installed capacity available in remaining refineries after rationalization, categorized by technology type, along the timeline (2024, 2030, 2040 and 2050).

Table 5.15: Process units installed capacity in specified years after rationalization - More Molecule

More Molecule EU+ refinery process unit capacity by technology type ('000 b/d except as noted)				
	EU+	EU+	EU+	EU+
Process unit	**2024**	**2030**	**2040**	**2050**
Primary separation process				
Crude/condensate distillation unit	13,232	11,004	4,911	2,048
Vacuum distillation unit	5,369	4,644	1,987	864
Conversion process				
FCC	2,128	1,887	820	183
VGO hydrocracker	1,706	1,510	785	411
Residue hydrocracker	261	199	29	15
Visbreaker/thermal cracking	1,291	1,111	416	210
Coking unit	565	506	337	206
Treatment and enhancement process				
Naphtha hydrotreater	2,983	2,543	997	326
FCC gasoline hydrotreater	613	582	339	146
Kero hydrotreater	855	733	257	112
Diesel hydrotreater	4,347	3,755	1,795	827
VGO hydrotreater	789	699	94	15
Resid hydrotreater	81	81	0	0
Naphtha isomerisation	465	381	140	52
Naphtha reformer	1,992	1,679	746	306
Alkylation	293	273	132	24
MTBE	10	9	2	1
Hydrogen generation units[1], *MMSCFD*	2,877	2,436	1,054	574
Specialties products manufacturing process				
Solvent extraction	132	132	32	25
Asphalt	304	237	76	48
Base oil production[2]	114	93	47	36
Aromatics PX production (integrated with refinery), Mt/d	291	234	161	117

Source: S&P Global Commodity Insights. (General indication of reliance on Commodity Insights analysis/data and external industry sources as appropriate.)

(1) Hydrogen generation units include SMR and POX units.

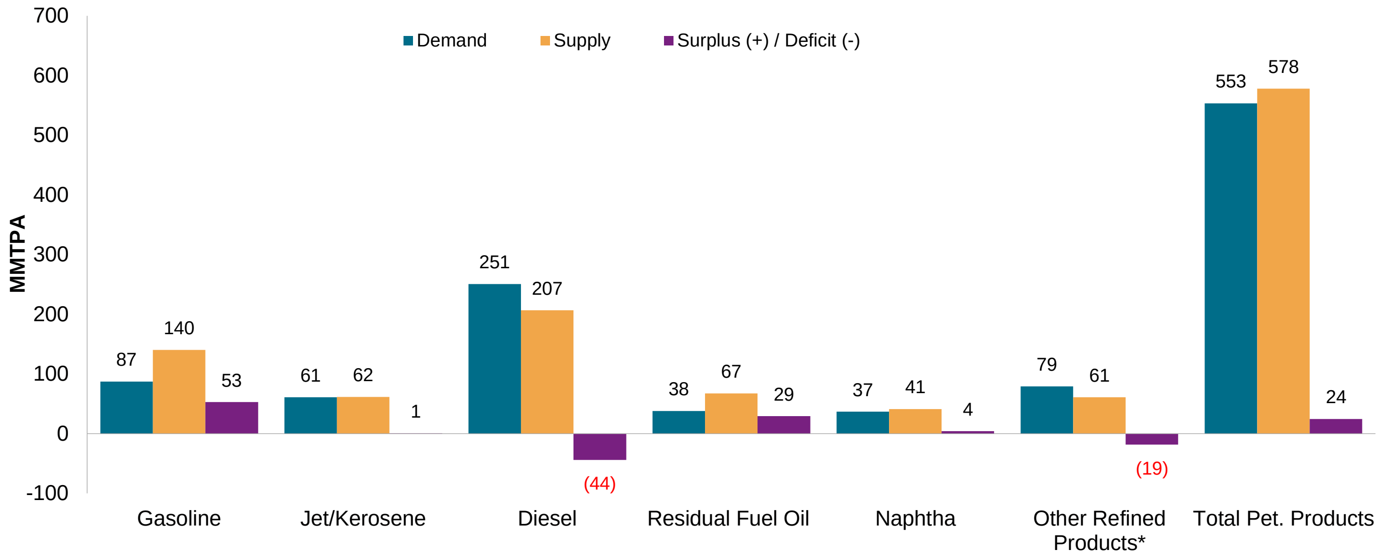
(2) Base oil production includes group I, II and III and naphthenic base oils.

5.4.2.3 EU+ Refined products balances

In the More Molecule scenario, demand for refined products is expect to decline long-term as a result of policy-driven changes, particularly around increase in the share of green fuels in the energy consumption basket. Green fuels are expected to make rapid inroads in the mid to long term in EU+ market, dampening conventional fuel demand significantly by 2050 in comparison to 2024 level. The decline in fuel demand is also expected to change the net trade position of refined products in the EU+ region.

In the More Molecule scenario in 2024, the EU+ region's position is the same as the Max Electron scenario. The region maintains a net deficit position with diesel demand accounting 45% of total refined products demand, while still having a surplus in gasoline and fuel oil.

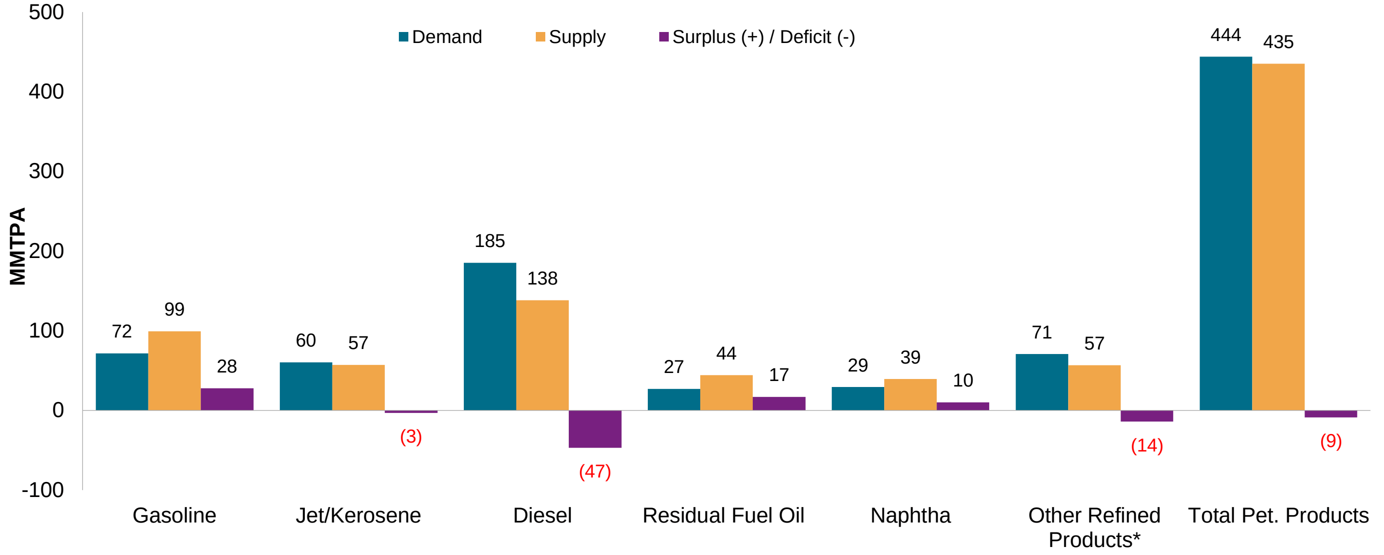
Figure 5.21: Refined Products Demand vs Supply (2024) - More Molecule



Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

Figure 5.22: Refined Products Demand vs Supply (2030) - More Molecule

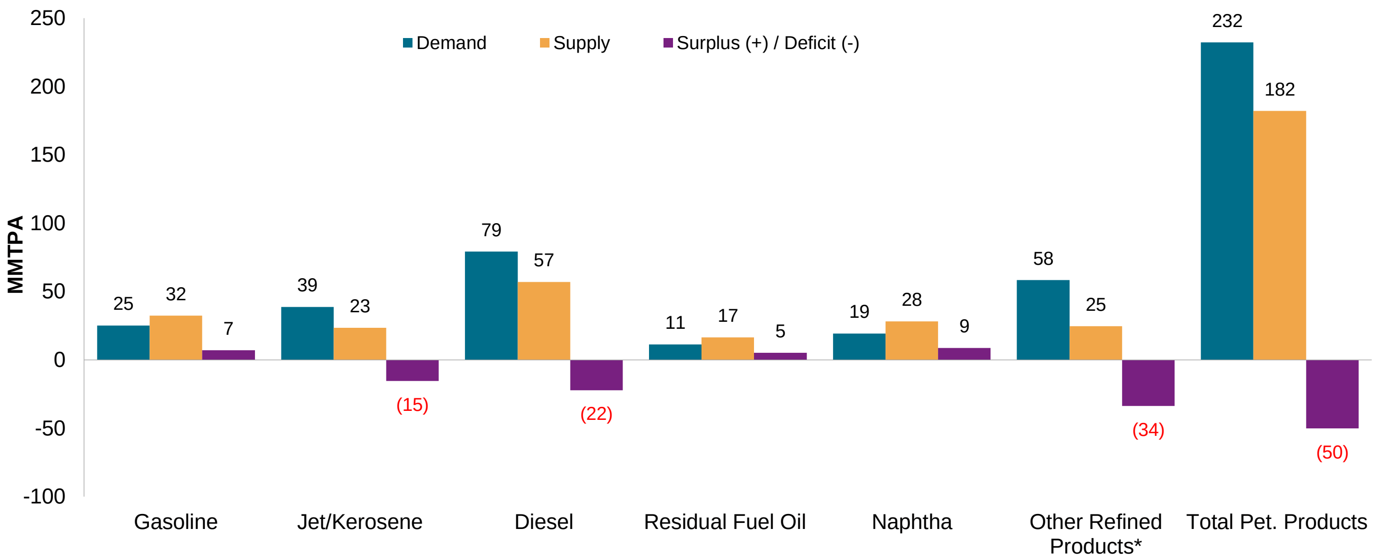


Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

By 2040, capacity rationalization driven by negative net margins will reduce production capacity, resulting in a deficit of approximately 50 MMTPA in refined products for the EU+, which represents 22% of total demand. It is anticipated that the jet fuel deficit will be 38%, while the diesel deficit will be 28%.

Figure 5.23: Refined Products Demand vs Supply (2040) - More Molecule



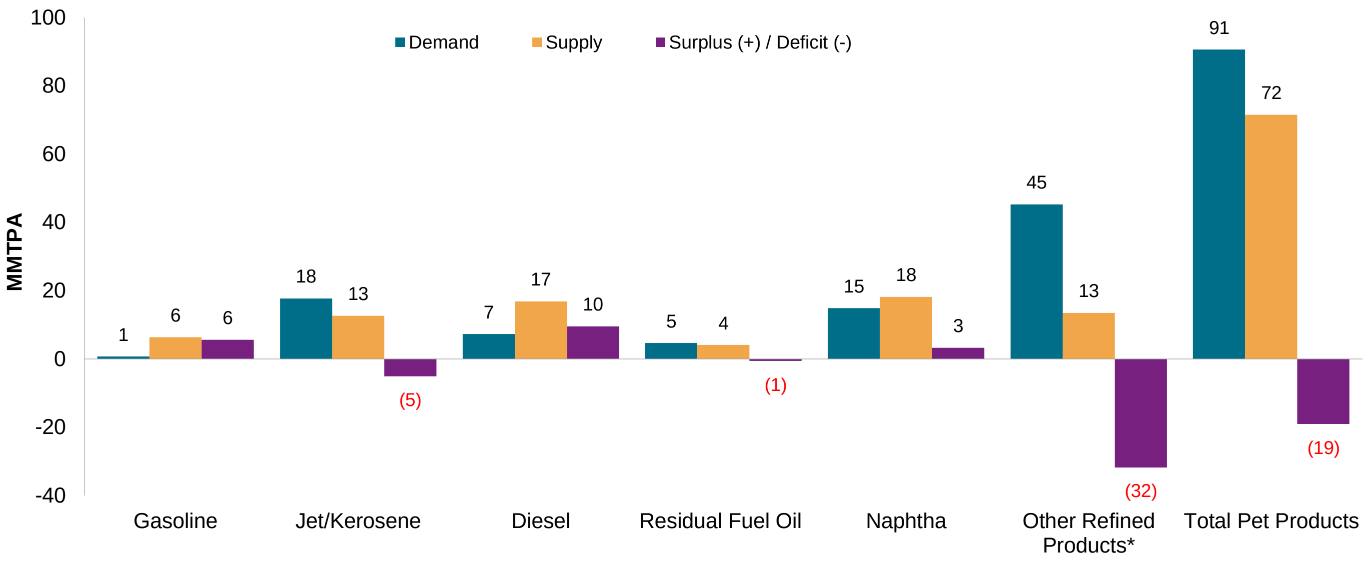
Source: S&P Global Commodity Insights.

*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

In the More Molecule scenario by 2050, due to further refining capacity rationalization, EU+ experiences a net deficit of refined products despite the decline in demand for fossil fuels. Fossil gasoline demand is negligible, leading to a modest surplus of 6 MMTPA. Fossil jet fuel demand remains higher than projected supply leading to a small deficit of 5 MMTPA. Diesel production however is higher than demand leading to a small surplus of 10 MMTPA, while fuel oil becomes nearly balanced. Fossil naphtha is expected to be in surplus by 3 MMTPA.

Other refined products account for approximately 49% of the total refined product demand in 2050. As in the Max Electron scenario, among these products, asphalt has the largest demand equivalent to 11.7 MMTPA. However, due to significant refinery rationalization after 2035, the supply of asphalt is expected to decrease to only 2.6 MMTPA in 2050.

Figure 5.24: Refined Products Demand vs Supply (2050) - More Molecule



Source: S&P Global Commodity Insights.

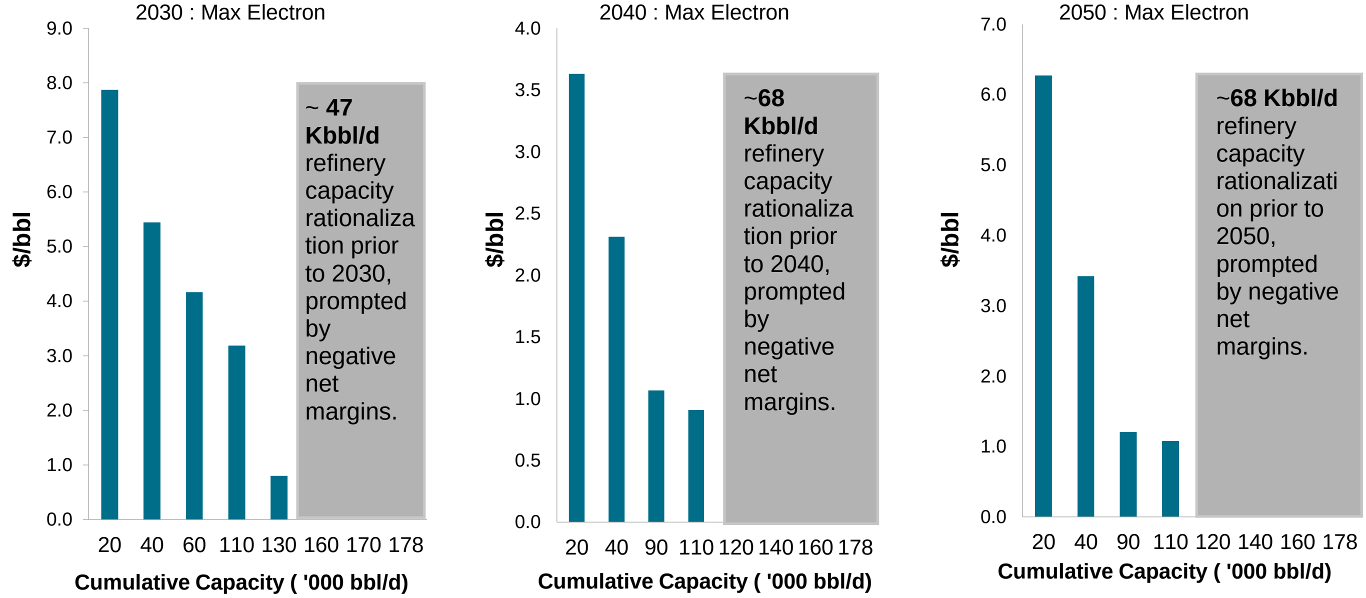
*Other Refined Products Include LPG, Base Oil Group I, II and III, Pet coke, Sulfur, Asphalt and Petrochemical products e.g., BTX, Propylene

5.4.3 Net Margin for specialty refineries

In 2024, EU+ operates 8 specialty refineries with a combined capacity of 178 thousand barrels per day (KBPD). These refineries primarily focus on specialty product production e.g., bitumen and base oils.

In both scenarios More Molecule and Max Electron, they have been affected by the challenging low-margin environment, resulting in the rationalization of 4 such refineries by 2040. This rationalization corresponds to approximately 38% of the total installed capacity of these refineries. Post 2040, we expect no further rationalization till 2050.

Figure 5.25: Net margin and rationalization outlook for specialty refineries – Max Electron & More Molecule



Margins include emission costs
Source: S&P Global Commodity Insights.
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Margins include emission costs
Source: S&P Global Commodity Insights.
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Margins include emission costs
Source: S&P Global Commodity Insights.
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5.4.4 Regional refinery rationalization

For regional refinery rationalization, the EU+ is divided into seven regions for the period 2024-2040 as per Table 5.16, and three regions for the period 2040-2050 as per Table 5.17.

Table 5.16 EU+ country grouping for 2024, 2030 and 2040

Region	Countries
A	United Kingdom, Ireland
B	Norway, Finland, Sweden, Denmark
C	Belgium, the Netherlands, Luxembourg
D	Croatia, Italy, Portugal, Spain, Malta
E	France, Germany
F	Greece, Bulgaria, Romania, Cyprus
G	Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Latvia, Estonia

Table 5.17 EU+ country grouping for 2050

Region	Countries
X	United Kingdom, Ireland, Norway, Finland, Sweden, Denmark, Belgium, the Netherlands, Luxembourg
Y	Croatia, Italy, Portugal, Spain, Greece, Bulgaria, Romania, Cyprus, Malta
Z	France, Germany, Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Estonia, Latvia

Figure 5.26: Year-wise remaining refineries for Max Electron and More Molecule scenarios

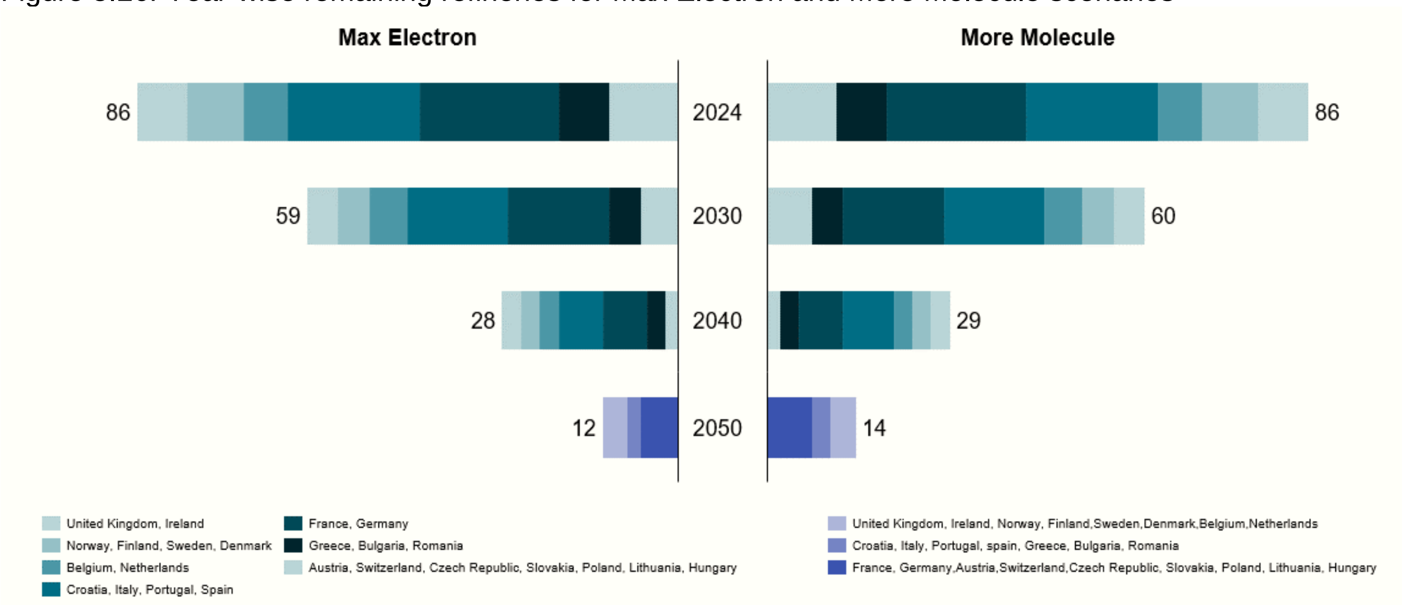
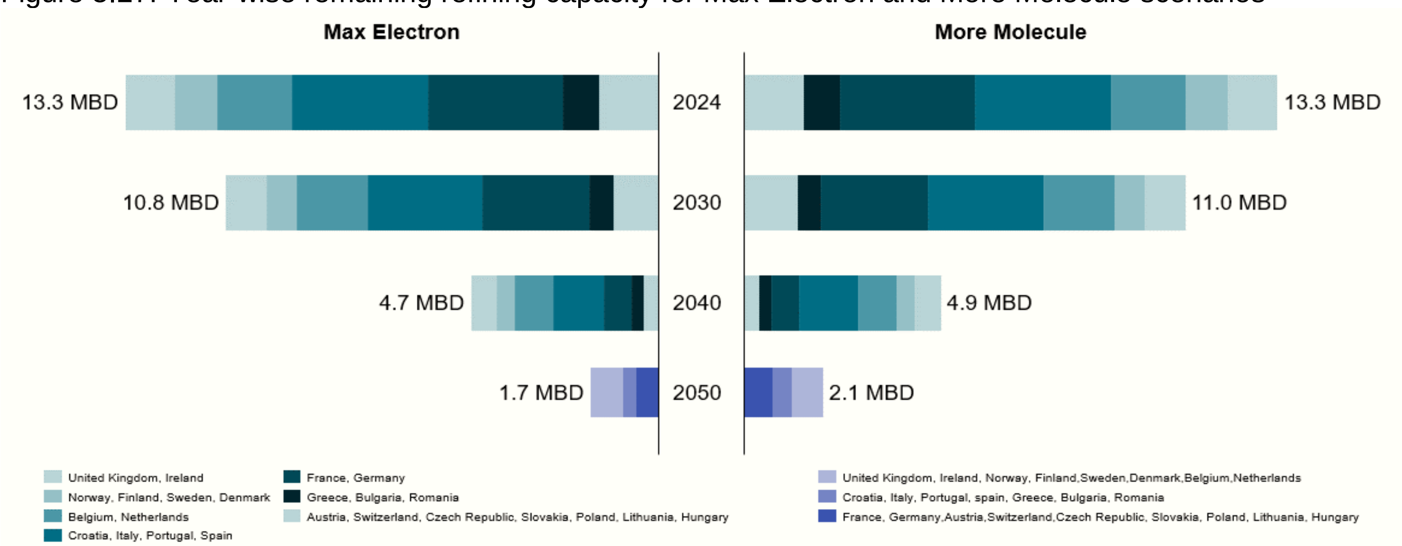


Figure 5.27: Year-wise remaining refining capacity for Max Electron and More Molecule scenarios



Conventional refinery capacity rationalization is expected to be significant in both scenarios. Tables 5.18 and 5.19 provide a comprehensive overview of the anticipated refining capacity rationalization between 2024 and 2050.

By 2030, a reduction of approximately 19% in installed capacity is anticipated in the Max Electron scenario, and an 18% reduction is expected in the More Molecule scenario. These reductions are a result of announced closures by companies and rationalization driven by negative net margins.

Post 2035, when free allowances for CO2 emissions will no longer be given, refinery margins will likely be severely impacted. As a result, major refining capacity rationalization is projected, equivalent to 46% of the total installed capacity in both scenarios.

Further refining capacity rationalisation is expected beyond 2040 given lower demand for refined products. Refining capacity would amount to some 2.97 MBPD in the Max Electron scenario and 2.8 MBPD under More Molecule. These figures represent 22% and 21% of the 2024 installed capacity in the respective scenarios.

Ultimately, by 2050 the final remaining installed capacity is expected to be 1.7 Mbpd in the Max Electron scenario and 2.1 Mbpd in the More Molecule scenario.

Please refer to Table 5.18 and Table 5.19 for detailed information on the regional remaining refining capacity for the time period of 2024-2040 and for 2050 respectively.

Table 5.18 EU+ region-wise refining capacity for 2024-2040

		Max Electron capacity (MBPD)			More Molecule capacity (MBPD)		
Region	**Countries**	**2024**	**2030**	**2040**	**2024**	**2030**	**2040**
A	The United Kingdom, Ireland	1.3	1.0	0.6	1.3	1.0	0.6
B	Norway, Finland, Sweden, Denmark	1.0	0.8	0.4	1.0	0.8	0.4
C	Belgium, the Netherlands, Luxembourg	1.9	1.8	1.0	1.9	1.8	1.0
D	Croatia, Italy, Portugal, Spain, Malta	3.4	2.9	1.3	3.4	2.9	1.5
E	France, Germany	3.4	2.7	0.7	3.4	2.7	0.7
F	Greece, Bulgaria, Romania, Cyprus	0.9	0.6	0.3	0.9	0.6	0.3
G	Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Latvia, Estonia	1.5	1.1	0.4	1.5	1.3	0.4
	Total	**13.3**	**10.8**	**4.7**	**13.3**	**11.0**	**4.9**

Table 5.19 EU+ region-wise refining capacity for 2050

		Max Electron capacity (MBPD)	More Molecule capacity (MBPD)
Region	**Countries**	**2050**	**2050**
X	The United Kingdom, Ireland, Norway, Finland, Sweden, Denmark, Belgium, the Netherlands, Luxembourg	0.8	0.8
Y	Croatia, Italy, Portugal, Spain, Greece, Bulgaria, Romania, Cyprus, Malta	0.3	0.5
Z	France, Germany, Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Estonia, Latvia	0.5	0.8
	Total	**1.7**	**2.1**

Please refer to Table 5.20 and Table 5.21 for detailed information on the region-wise remaining refineries for 2024-2040 and 2050, respectively.

Table 5.20 EU+ Region-wise refineries for 2024-2040

		Max Electron			More Molecule		
Region	**Countries**	**2024**	**2030**	**2040**	**2024**	**2030**	**2040**
A	The United Kingdom, Ireland	8	5	3	8	5	3
B	Norway, Finland, Sweden, Denmark	9	5	3	9	5	3
C	Belgium, the Netherlands, Luxembourg	7	6	3	7	6	3
D	Croatia, Italy, Portugal, Spain, Malta	21	16	7	21	16	8
E	France, Germany	22	16	7	22	16	7
F	Greece, Bulgaria, Romania, Cyprus	8	5	3	8	5	3
G	Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Latvia, Estonia	11	6	2	11	7	2
	Total	86	59	28	86	60	29

Table 5.21 EU+ Region-wise refineries for 2050

		Max Electron	More Molecule
Region	**Countries**	**2050**	**2050**
X	The United Kingdom, Ireland, Norway, Finland, Sweden, Denmark, Belgium, Netherlands, Luxembourg	4	4
Y	Croatia, Italy, Portugal, Spain, Greece, Bulgaria, Romania, Cyprus, Malta	2	3
Z	France, Germany, Austria, Switzerland, the Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Estonia, Latvia	6	7
	Total	12	14

6 Low-carbon Fuels Supply

The total final energy demand split determined in the Max Electron and More Molecule scenarios provide an indication of the supply requirements. SPGCI identifies the renewable fuel capacity in the EU+ countries and estimates the additional clean fuels investments required to enable the supply to match the required demand.

6.1 Biofuel supply

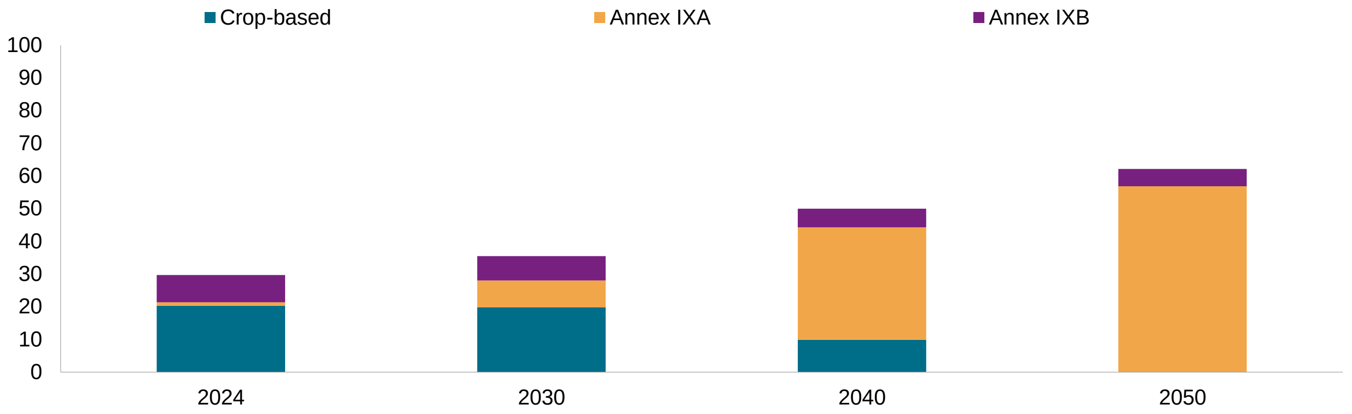
To determine the liquid biofuels supply requirement, SPGCI first takes the total final energy demand for liquid biofuels in the Max Electron and More Molecule scenarios. The demand for liquid biofuels is then allocated to three different biofuel types according to their feedstock class: food and feed crop-based biofuels, Annex IXA feedstock-based biofuels and Annex IXB feedstock-based biofuels. Liquid biofuels demand includes bio-gasoline, biodiesel, bio-jet and bio-LPG demand that is coming from fuel consumption.

Eurostat consumption data in 2021 shows that compliant biofuels from food and feed crops amounted to 4% of total fuel used in transport. While the EU cap on biofuels from food and feed crops is 7%, the current average food and feed crop-based biofuel content is around 4.5% considering both the RED cap and national legislations. Therefore, SPGCI applied a 4.5% constraint on the contribution of food and feed crop-based biofuels to total energy demand in transportation in the Max Electron and More Molecule scenarios. The 1.7% cap on the Annex IXB biofuel contribution, as set by the Renewable Energy Directive, was also applied (including for UK where this regulation does not apply) and it was assumed that any remaining demand of biofuels is to be met by Annex IXA biofuels. To comply with GHG targets, food and feed crop-based biofuels were phased out to 0 by 2050.

In the Max Electron case, demand for food and feed crop-based biofuels will enter long-term decline in line with falling fuel demand and it will furthermore fall to zero by 2050 to meet net zero emissions because of the higher embedded CO_2 content of food and feed crop-based biofuels. In this scenario:

- food and feed crop-based liquid biofuel demand decreases from 20.35 MMtoe in 2024 to 19.84 MMtoe in 2030 and then declines to zero by 2050
- Annex IXA biofuels increase from 1.08 MMtoe in 2024 to 8.22 MMtoe in 2030 and to 56.90 MMtoe in 2050
- Annex IXB biofuels decrease from 8.27 MMtoe in 2024 to 7.46 MMtoe in 2030 before declining to 5.24 MMtoe in 2050 due to the limitations of the 1.7% cap on Annex IXB biofuels
- total liquid biofuels energy demand increases from 29.69 MMtoe in 2024 to 35.52 MMtoe in 2030 to 62.13 in 2050

Figure 6.1: Max Electron EU+ liquid biofuel energy demand by feedstock class (MMtoe)



Source: S&P Global Commodity Insights.

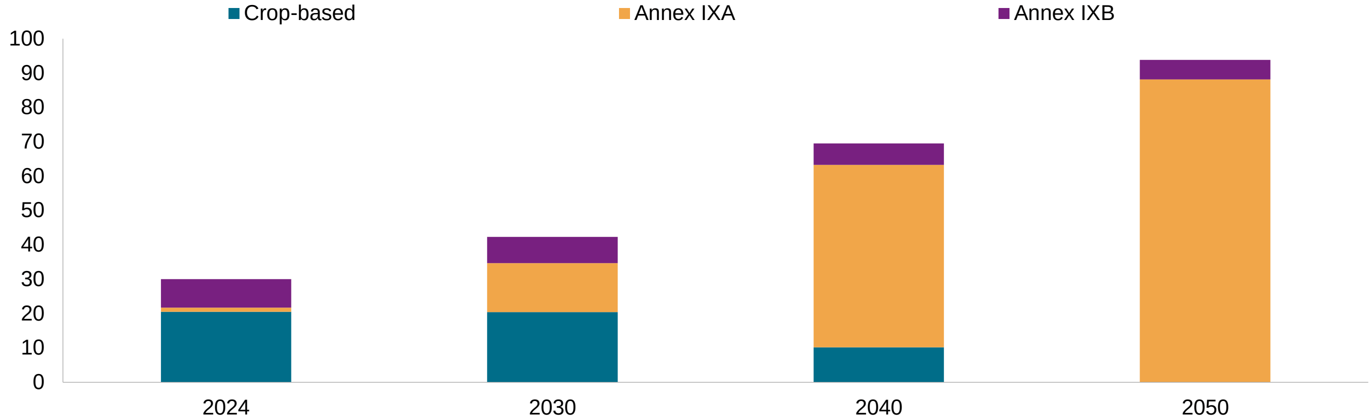
In the More Molecule case, a higher total liquid biofuels demand is modelled due to the lower penetration of electrification; therefore, there is a higher reliance on low carbon liquid fuels. In this scenario:

- Food and feed crop-based biofuel demand decreases from 20.55 Mtoe in 2024 to 20.39 Mtoe in 2030 and declines to zero by 2050
- Annex IXA biofuel demand increases from 1.16 Mtoe in 2024 to 14.25 Mtoe in 2030 and to 88.15 Mtoe in 2050
- Annex IXB biofuel demand decreases from 8.27 Mtoe in 2024 to 7.67 Mtoe in 2030 and declines to 5.72 Mtoe in 2050
- Total liquid biofuels energy demand increases from 29.99 Mtoe in 2024 to 42.32 Mtoe in 2030 to 93.88 Mtoe in 2050

Table 6.1: Biofuel demand outlook in both scenarios

Type of fuel demand	Max Electron (Mtoe)				More Molecule (Mtoe)			
	2024	2030	2050	Increase/ decrease	2024	2030	2050	Increase/ decrease
Food and feed crop-based biofuel demand	20.35	19.84	0	↓	20.55	20.39	0	↓
Annex IXA biofuel demand	1.08	8.22	56.90	↑	1.16	14.25	88.15	↑
Annex IXB biofuel demand	8.27	7.46	5.24	↓	8.27	7.67	5.72	↓
Total liquid biofuels energy demand	29.69	35.52	62.13	↑	29.99	42.32	93.88	↑

Figure 6.2: More Molecule EU+ liquid biofuel energy demand by feedstock class (MMtoe)



Source: S&P Global Commodity Insights.

After these demand profiles in the Max Electron and More Molecule scenarios were determined, SPGCI moved on to the supply of liquid biofuels.

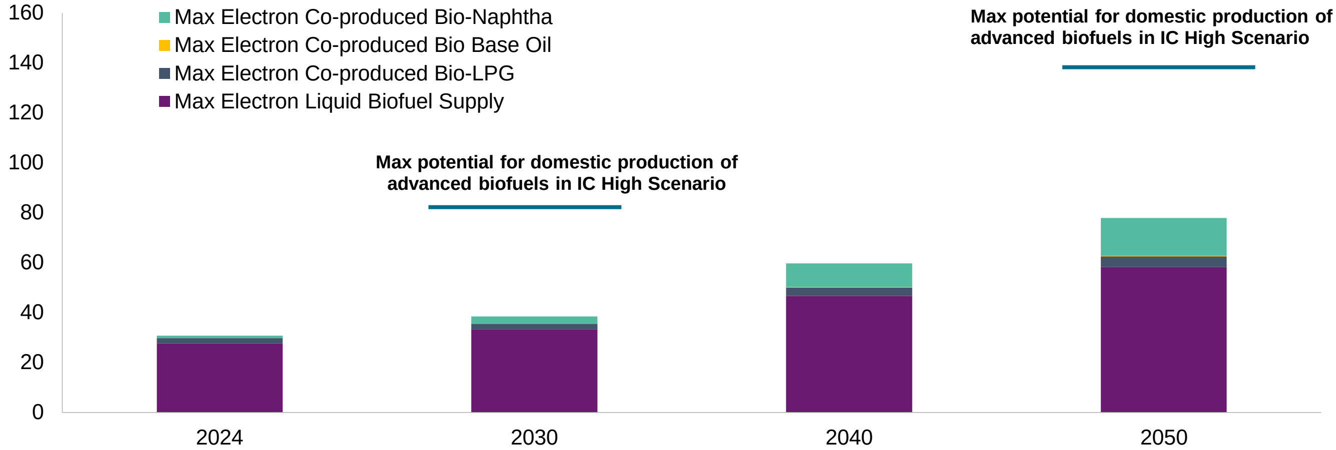
SPGCI compares the total liquid biofuel energy demand in the Max Electron and More Molecule scenarios to the potential biofuel availability in 2030 and 2050 as reported in the CONCAWE-Imperial College London "Sustainable Biomass Availability in the EU, to 2050" report. This was to understand whether there is sufficient domestically advanced biofuel feedstock to meet potential Annex IXA feedstock biofuel demand. Concawe-ICL calculated potential availability for the three following scenarios:

- Low: Low mobilization - Farming and forest practices at 2020 levels
- Medium: Improved mobilisation in selected countries in EU with high biomass availability
- High: Enhanced availability through R&I and improved mobilisation in all EU countries

The estimates in these scenarios show that improved research and innovation can help realise the higher potentials of advanced feedstock availability. Furthermore, the potentials shown in the Imperial College report could increase due to Annex IX of the RED being revised. This would allow interseasonal crops and crops on severely degraded land to be considered as Annex IXA if used to produce SAF.

The Imperial College report shows that the potential advanced and waste-based biofuels (EU domestic production) availability in 2030 is between 28.9 MMtoe in the low scenario and 79.2 MMtoe in the high scenario and in 2050 the availability is 31.5 MMtoe in the low scenario and 137.2 MMtoe in the high scenario. The SPGCI liquid bioproducts demand in the Max Electron scenario falls within the low to middle of this range whereas in the More Molecule scenario by 2050 our projected bioproducts demand approaches the maximum range. This implies that improved farming and forestry practices will be required to realise the higher mobilization of biomass and reduce the need for imports, particularly in the More Molecule scenario where there is a greater requirement for advanced feedstocks.

Figure 6.3: CONCAWE/Imperial College London Potential Biofuel Availability (MMtoe) - Max Electron



Source: CONCAWE & Imperial College London, S&P Global
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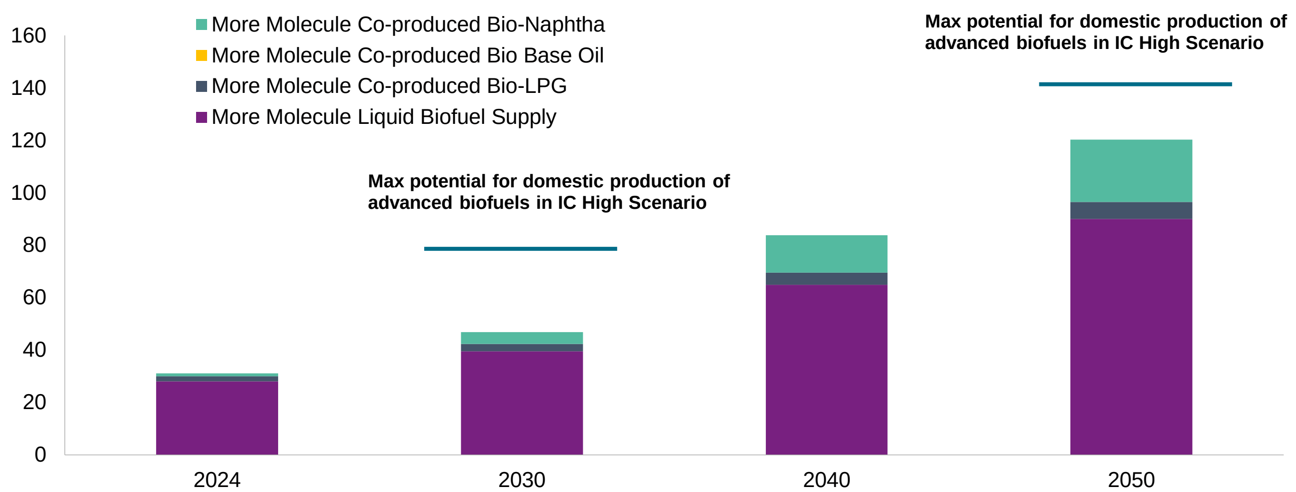
Figure 6.4: CONCAWE/Imperial College London Potential Biofuel Availability (MMtoe) - More Molecule



Source: CONCAWE & Imperial College London, S&P Global
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SPGCI maintains a database of FAME plants, fuel ethanol plants and bio-refineries, updated by the SPGCI Biofuels Value Chain Service (BVCS) team of researchers and analysts. This database records global biofuel plants that are operating and the projects that have been announced publicly by companies in the industry up to 2030.

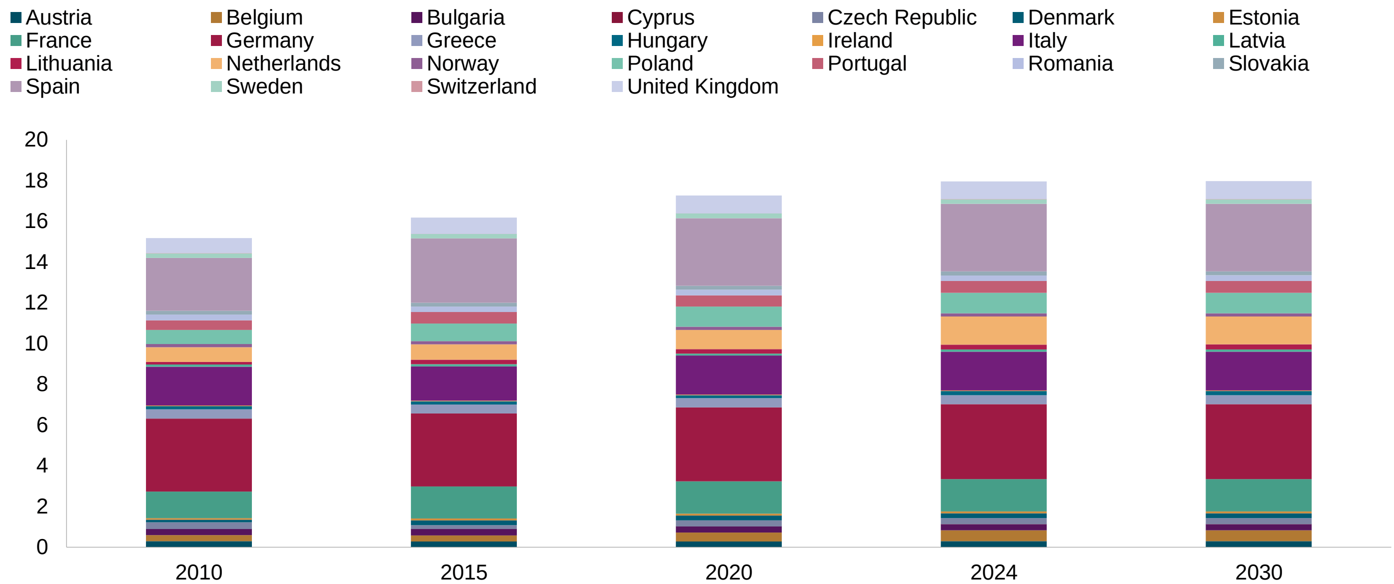
SPGCI used this database to identify the existing and expected biofuel capacity in the EU+ countries up to 2030. The FAME plants, fuel ethanol plants and bio-refineries in this database refer to plants processing all feedstock types from first-generation to advanced feedstocks.

From the database, SPGCI selected the FAME plants, fuel ethanol plants and bio-refineries that were located in the EU+ countries and were either operational, firm or speculative. Operational refers to plants that are currently operating, firm refers to plants that have been announced with the final investment decision made and speculative refers to plants that have been announced but no final investment decision has yet been made. Co-processed volumes were not included in the bio-refinery capacities. Bio-refineries include the following technology pathways:

- Alcohol-to-Jet Synthetic Paraffinic Kerosene (ATJ-SPK),
- Biomass-to-liquids (BtL)
- Catalytic esterification
- Fischer-Tropsch Synthetic Paraffinic Kerosene (FT-SPK),
- Hydrotreated Esters and Fatty Acids (HEFA),
- HEFA-SPK and Hydrothermal Liquefaction (HTL).

BtL bio-refinery refers to a speculative plant using pyrolysis and hydrotreatment technology to convert Annex IXA feedstock to SAF. The total operational, firm and speculative production capacity of EU+ FAME plants in 2030 is expected to be 17.97 MMtoe.

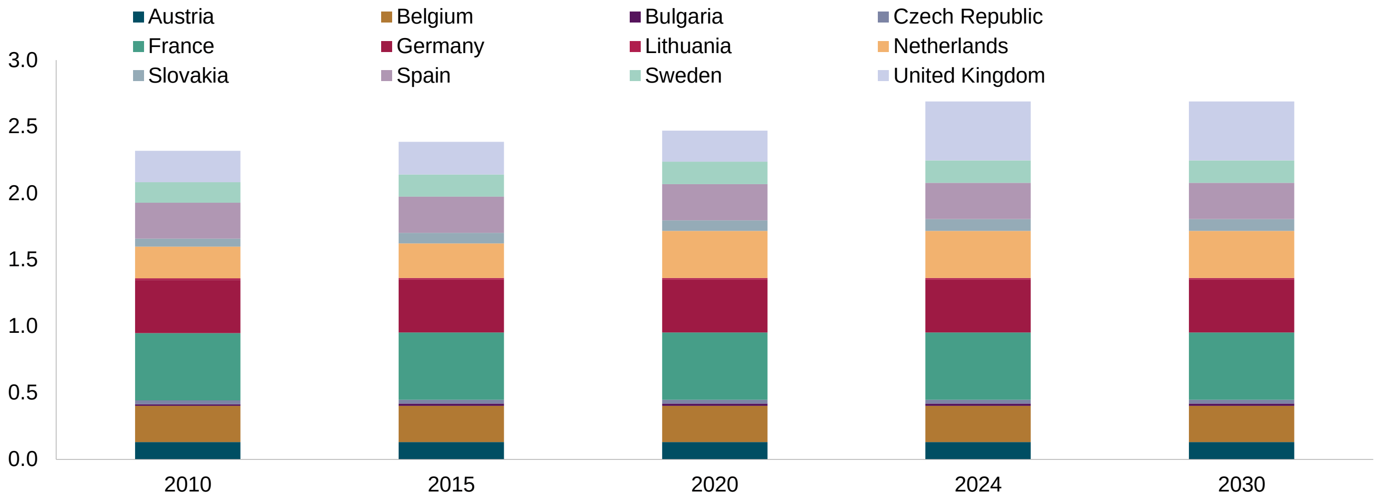
Figure 6.5 – EU+ FAME Capacity to 2030 (MMtoe)



Source: S&P Global Commodity Insights.

The total operational, firm and speculative production capacity of EU+ fuel ethanol plants in 2030 is expected to be 2.69 MMtoe.

Figure 6.6 – EU+ Fuel Ethanol Capacity to 2030 (MMtoe)



Source: S&P Global Commodity Insights.
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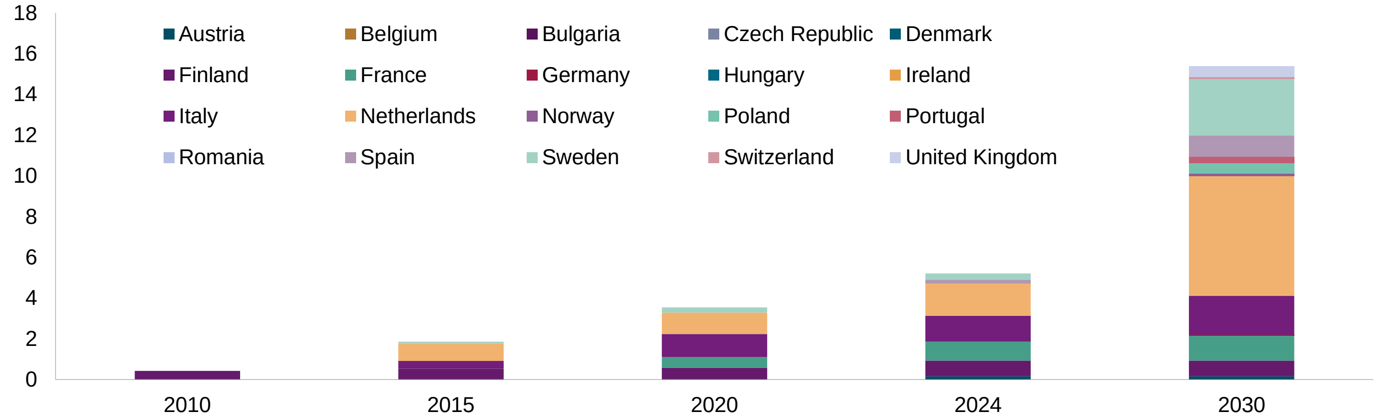
The total operational, firm and speculative production capacity of EU+ bio-refineries in 2030 is expected to be 15.39 MMtoe.

Figure 6.7 – EU+ Biorefinery* Capacity to 2030 (MMtoe)



*(includes ATJ-SPK, Biomass-to-liquids, Catalytic esterification, FT-SPK, GTL, HEFA, HEFA-SPK, HTL, MTJ-SPK)
Source: S&P Global Commodity Insights.
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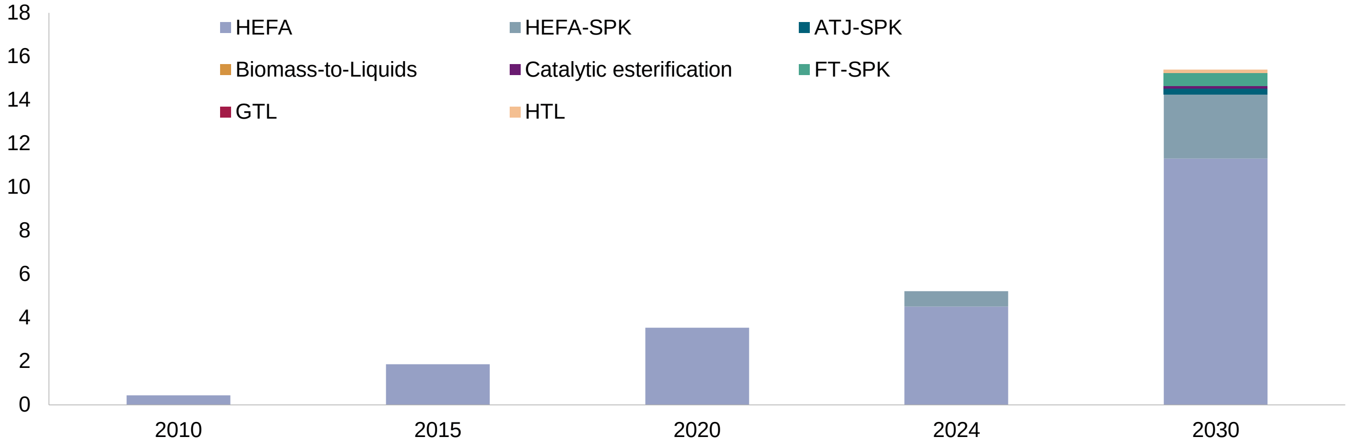
The majority of the bio-refinery production capacity is made up of HEFA and HEFA-SPK technology pathways. 92% of the expected bio-refinery capacity in 2030 is HEFA or HEFA-SPK, totalling 14.26 MMtoe in 2030.

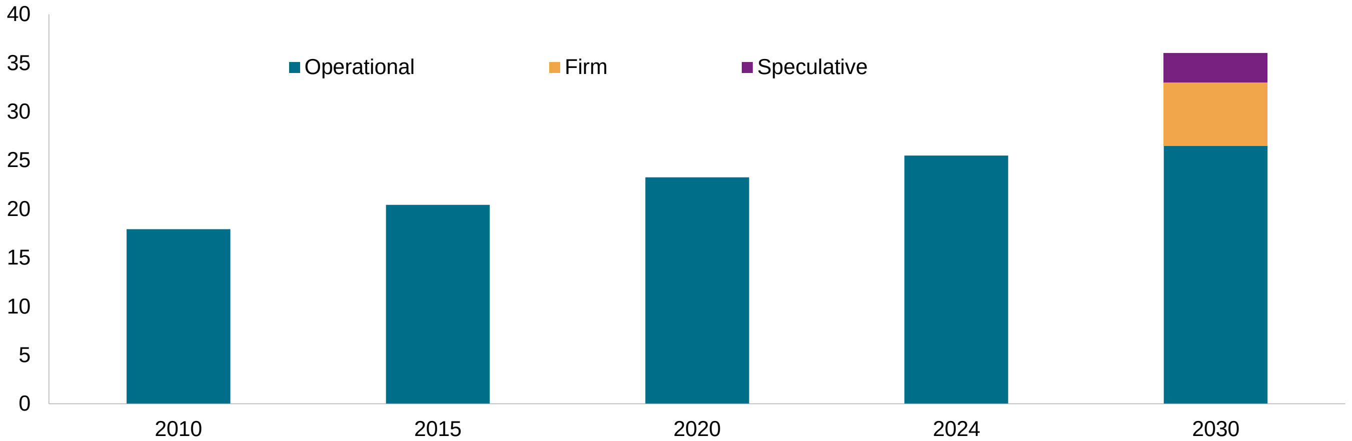
Figure 6.8 – EU+ Biorefinery* Capacity by Pathway (MMtoe)



*(includes ATJ-SPK, Biomass-to-liquids, Catalytic esterification, FT-SPK, GTL, HEFA, HEFA-SPK, HTL, MTJ-SPK)
Source: S&P Global Commodity Insights.

Collectively between the FAME plants, fuel ethanol plants and bio-refineries, 26.47 MMtoe of production capacity in 2030 is categorized as operational, 6.54 MMtoe as firm and 3.04 MMtoe as speculative.

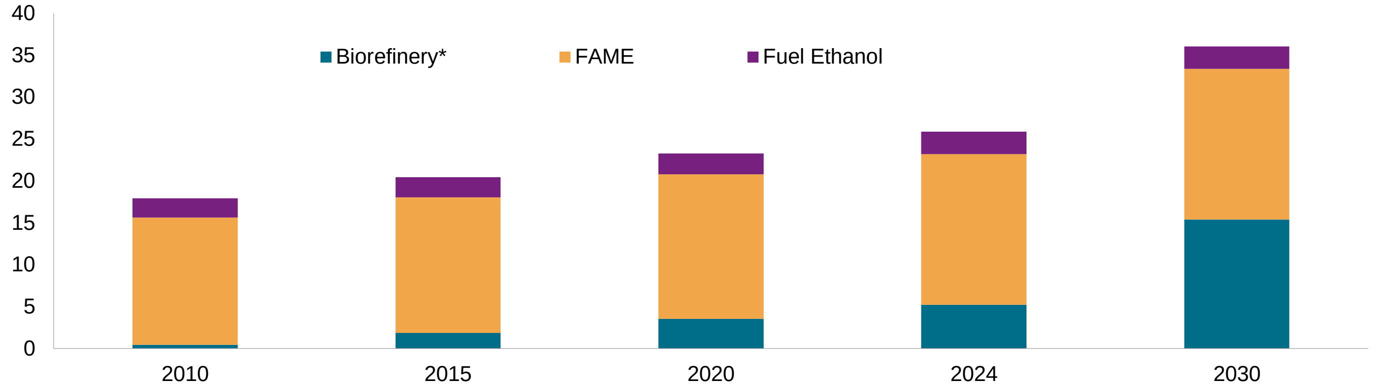
Figure 6.9 – EU+ Liquid Biofuel Production Capacity Status (MMtoe)



*(includes ATJ-SPK, Biomass-to-liquids, Catalytic esterification, FT-SPK, HEFA, HEFA-SPK, HTL, MTJ-SPK)
Source: S&P Global Commodity Insights.

Collectively, the total EU+ supply capacity from FAME, fuel ethanol and bio-refineries is expected to be 36 MMtoe in 2030.

Figure 6.10 – EU+ Total Biofuel Capacity (MMtoe)



*(includes ATJ-SPK, Biomass-to-liquids, Catalytic esterification, FT-SPK, HEFA, HEFA-SPK, HTL)
Source: S&P Global Commodity Insights.

These capacity figures are the 2024-2030 domestic production figures that SPGCI uses in the supply forecast and only includes stand-alone biofuel production capacity and not co-processed volumes. Any demand that is not met by the domestic production in 2024-2030 is assumed to be met by imports. The use of the demand forecast and the expected capacity up to 2030 enables us to build the biofuel supply and demand balance to 2030.

Based on the advanced biofuel availability potential given in the CONCAWE & Imperial College London report, it is concluded that with improved farming and forestry practices and research and innovation, there can be sufficient Annex IXA feedstocks within the EU to meet the Max Electron and More Molecule scenarios projected long-term demand. The more aggressive More Molecule scenario for liquid energy demand will require greater improvements in management practices and R&I to achieve a higher mobilization of biofeedstocks from within the EU. Additionally, SPGCI assumes that food and feed crop-based biofuel production will decline to zero in 2050 in order to comply with the GHG reduction targets that have to be met by 2050. Facilities producing food and feed crop-based biofuels could either become non-operational, or pivot to waste-based and advanced biofuels instead as food and feed crop-based biofuel demand declines.

The Annex IXB long-term supply is also constrained to meet the Annex IXB demand which is limited due to the 1.7% cap on Annex IXB demand.

Additionally, the long-term supply forecast is modelled to meet the demand of low GHG emission fuels to achieve net neutrality by 2050. Each of the liquid biofuel types discussed, crop-based biofuels, Annex IXA biofuels and Annex IXB biofuels, are allocated a GHG reduction factor by SPGCI.

Table 6.2: Biofuel consumption induced GHG reductions

	2024	2030	2050
Food and feed crop-based biofuel	50% GHG reduction	50% GHG reduction	50% GHG reduction
Annex IXA biofuel	93% GHG reduction	94% GHG reduction	98% GHG reduction
Annex IXB biofuel	85% GHG reduction	85% GHG reduction	87% GHG reduction

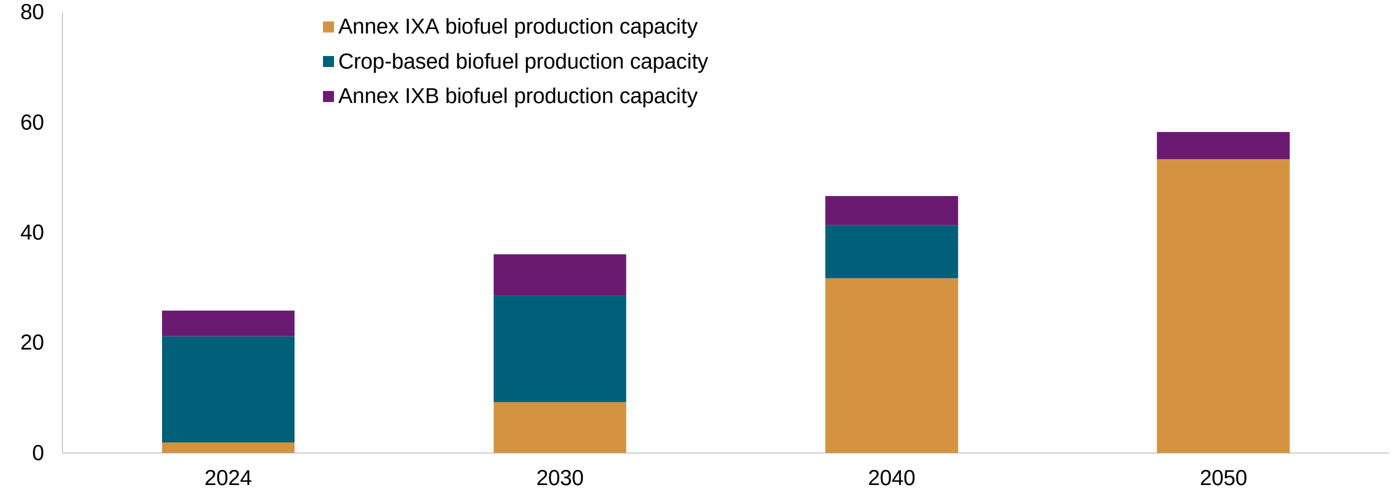
GHG reduction = GHG reduction as compared to fossil fuel equivalent.

Source: S&P Global

The supply is modelled with these carbon intensity factors, and this applies a further constraint on the amounts of each fuel that can be supplied and still achieve net zero carbon emissions by 2050.

With these assumptions and constraints applied, the total EU+ 2050 biofuels supply was modelled for each scenario.

Figure 6.11 – Max Electron EU+ Biofuel Supply (MMtoe)



Source: S&P Global Commodity Insights.
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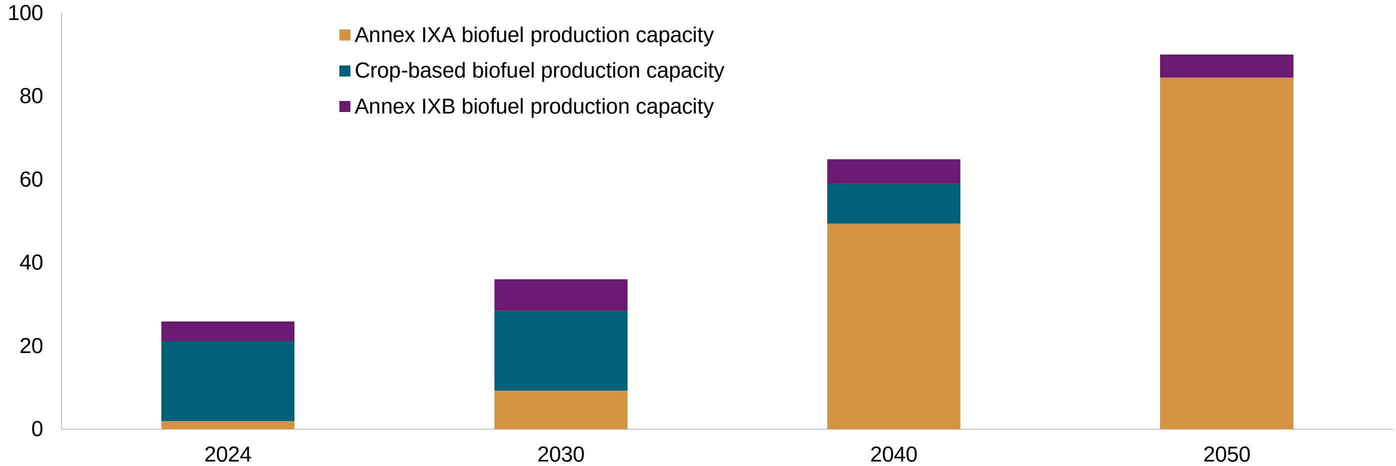
Figure 6.12 – More Molecule EU+ Biofuel Supply (MMtoe)



Source: S&P Global Commodity Insights.
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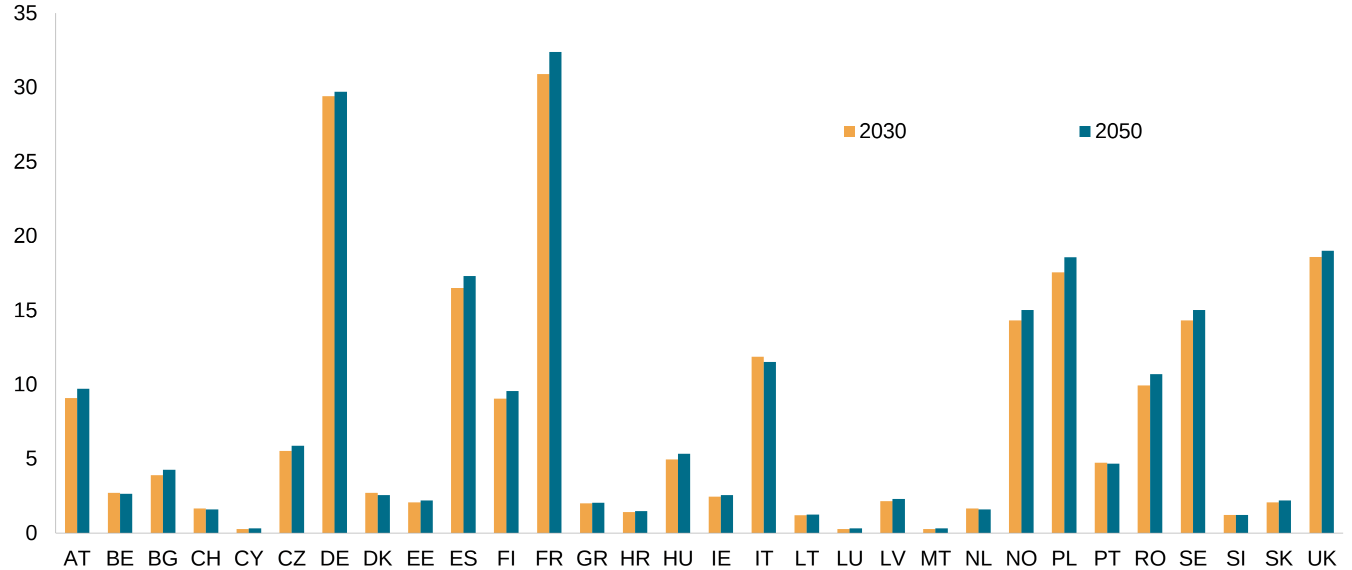
To determine the EU+ long-term supply from each country in 2050, SPGCI models where the 2050 Annex IXA biofuel is likely to be produced based on the biomass availability in each country. It is expected that Annex IXA biofuel production facilities will be built in proximity to where the available biomass is grown/produced, to avoid transporting low-energy density feedstock over long distances.

SPGCI utilized information from the CONCAWE & Imperial College London report. SPGCI added up the available cereal straw, maize stover, oil crop field residues, agricultural prunings, manure, secondary agricultural residues, lignocellulosic crops, stemwood, primary forest residues, secondary forest residues & post-consumer wood (PCW) and biowastes in each country available for bioenergy. SPGCI used the low case scenario to be conservative. For those countries not included in the Imperial College report, such as Norway, SPGCI assumed a similar biomass availability in the missing country to a featured country with a similar biomass-density profile.

SPGCI used the country-wise Annex IXA feedstock availability data from the Imperial College report to produce a ratio by country of where the feedstock can be produced. This ratio of where the total feedstock will be available across the EU+ countries in 2050 from the Imperial College report was applied to the total 2050 Annex IXA biofuel supply as determined by the scenarios.

Figure 6.13 – CONCAWE-ICL Annex IXA Feedstock Availability (Low case: for bioenergy), MMToe



Source: CONCAWE, Imperial College London, SPGCI

For example, Austria's Annex IXA total feedstock availability in 2050 according to the CONCAWE & Imperial College London report is 9.7 MMtoe. The total feedstock availability in 2050 according to the report and SPGCI assumptions of non-featured countries (Norway, Switzerland and UK) is 258 MMtoe, giving Austria a 3.8% share of the total feedstock availability. Therefore, SPGCI assumes that of the 2050 supply for Annex IXA biofuels, Austria will produce 3.8% of the supply. This methodology was applied across all EU+ countries to give the 2050 supply scenario on a country-by-country basis.

6.2 Biofuels and E-fuels production cost analysis

SPGCI reviewed the cost of production evolution of biofuels and E-Fuel using different technology pathways.

Table 6.3: List of technologies used with different feedstocks

Product	Technology pathways	Feedstock Type
RD UCO – Annex IXB	Hydrotreating	Used cooking oil (UCO)
RD Pyoil – Annex IXA	Hydrotreating + Pyrolysis	Biomass (corn stover)
FAME UCO – Annex IXB	Transesterification	Used cooking oil
RD BTL - Annex IXA	BTL (gasification + FT)	Biomass (corn stover)
SAF ATJ – SAF	Alcohol to jet	Ethanol
SAF ATJ2 – SAF, Annex IXA	Alcohol to jet – 2nd generation	Ethanol 2G
RD - POME – Annex IXA	Hydrotreating	POME
RD - E-Fuel	Fischer-Tropsch	Biogenic CO2 and green hydrogen
RD – Coprocessing, RFNBO	Co-processing as refinery feedstock	Green Hydrogen

SPGCI maintains an in-house production cost analysis model of the above-mentioned technological pathways. The production cost model considers the EU region in the cost calculations and all the input parameters of prices and other costs that are EU specific. In the production cost model, the main elements used are CAPEX (battery limit and offsites), OPEX (fixed cost, variable cost) and feedstock costs for the different considered pathways. The feedstock values are either coming from a feedstock production cost, for example ethanol, or the feedstock prices from SPGCI forecasted long term price projections such as UCO and corn stover. The ROI is assumed at 6% in the production cost model. For the e-fuel production cost analysis, the average price of green electricity and green hydrogen between Germany and Portugal is used in the model.

Table 6.4: Constant 2022 US$ prices used in biofuels and e-fuels cost analysis

	2024	2030	2040	2050
Electricity price for hydrogen production, $/MWh	78	61	58	47
Europe – green hydrogen average $/tonne	6852	5910	5333	4937
Natural gas price $/tonne	18.54	8.48	8.62	10.25
Jet $/tonne	815	714	691	659
Diesel $/tonne	767	675	652	622

A production cost index chart is prepared below, to understand the production cost evolution of biofuels and e-fuels as compared to the fossil fuel equivalent price. The index calculated is using formula:

$$INDEX = 100\ x\ \frac{(\text{Production cost})}{\text{Fossil fuel equivalent price}}$$

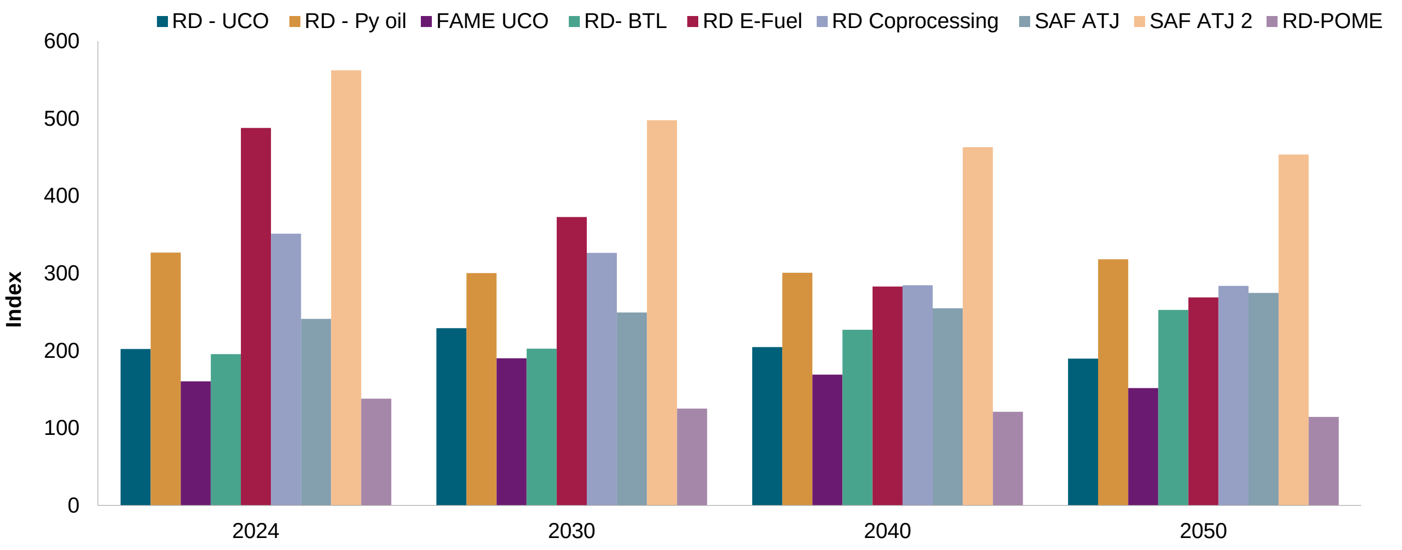
Production cost = Cost of production of the product through the technology pathway.

Fossil fuel equivalent price = Forecast price of the fossil fuel equivalent product from SPGCI longer term forecast.

SPGCI expects that the overall cost of production of most advanced low carbon fuels will reduce with time (Figure 6.14). However, the feedstock price evolution for some pathways can bring variation in the overall production cost of that pathway over time. For example, according to the forecast, the UCO price will increase from 2024 to 2030 and will reduce from 2030 to 2050. The influence of these price fluctuations is reflected in the cost index in the chart as UCO price is the main cost driver for the UCO-based biofuel pathways. With time, the overall production cost will reduce for RD-Pyoil. However, the hydrogen feedstock price will slightly increase the overall cost index of pyoil from 2040 to 2050.

Biomass to liquid production cost increases slightly with time due to corn stover feedstock price increase, due to impact of increase of fertilizer and collection cost. The cost to produce these advanced fuels remains higher compared to the fossil fuel equivalent in 2050 for the EU+, excluding any CO_2 cost from ETS II, which could have an important impact on the price of fossil fuels.

Figure 6.14 – Biofuel and E-Fuel Production cost index in EU



Source: S&P Global Commodity Insights.

Note: RD- Renewable Diesel, FT – Fischer-Tropsch
Note: Technology evaluation is kept at 2050 for uniformity. Some of the technology will be phased out as the feed crops demand move to zero in the long term.

6.3 RFNBO Hydrogen Supply

Green hydrogen will be one of the key feedstocks for production of synthetic fuels in the transport sector. The supply side forecast of RFNBOs – Renewable Fuels of Non-Biological Origin, is developed using the green hydrogen domestic generation potential for the EU+.

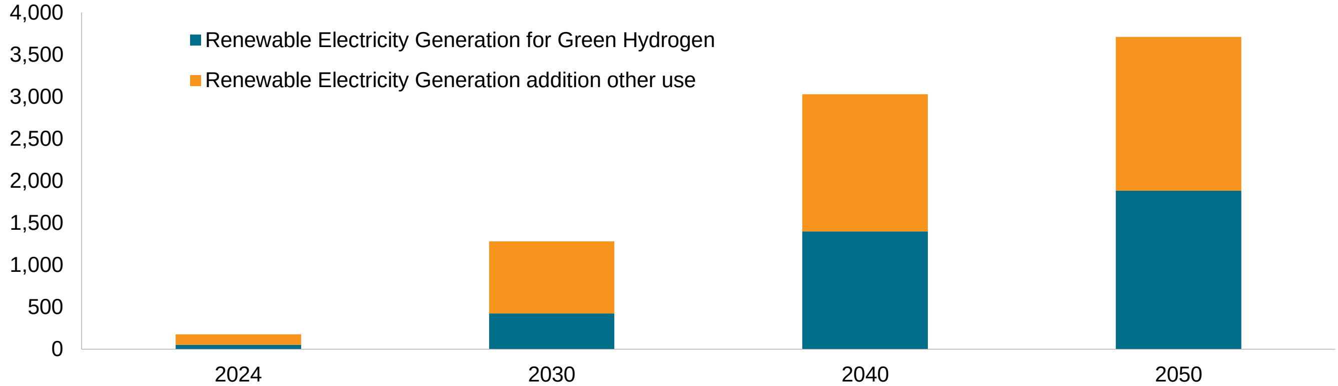
Domestic EU+ generation potential for green hydrogen is based on the additional renewable electricity generation added each year in the EU + as per SPGCI Green Rules scenario.

In the Green Rules scenario, SPGCI projected the potential availability of renewable electricity in the EU+. This forecast is based on several criteria, including the physical limitations and potential of renewables in various regions, economic viability, transmission system operators' outlooks in different countries, historical growth trends of renewables, potential acceleration in growth rates, and relevant policies and subsidies.

It is expected that by 2030, renewable energy will meet the power demand from sectors such as transport, district heating and cooling, and industry. The availability of renewable energy therefore constrains the domestic hydrogen available for the transport sector, while considering competing uses of green hydrogen. Additionally, around 35% of the newly added renewable electricity will be used for green hydrogen production by 2030, increasing to 56% of total renewable electricity generation by 2050.

Overall additional renewable electricity generation potential above 2024 level in EU+ will be around 3712 TWh by 2050 as per Green Rules, of which 1884 TWh to be used for producing RFNBO green hydrogen in 2050, which will be a challenge. For context in 2022 the EU+ total electricity consumption was 2895 TWh.

Figure 6.15 – Forecasted EU+ Renewable Electricity additional generation v 2023 (TWh)



Source: S&P Global Commodity Insights.

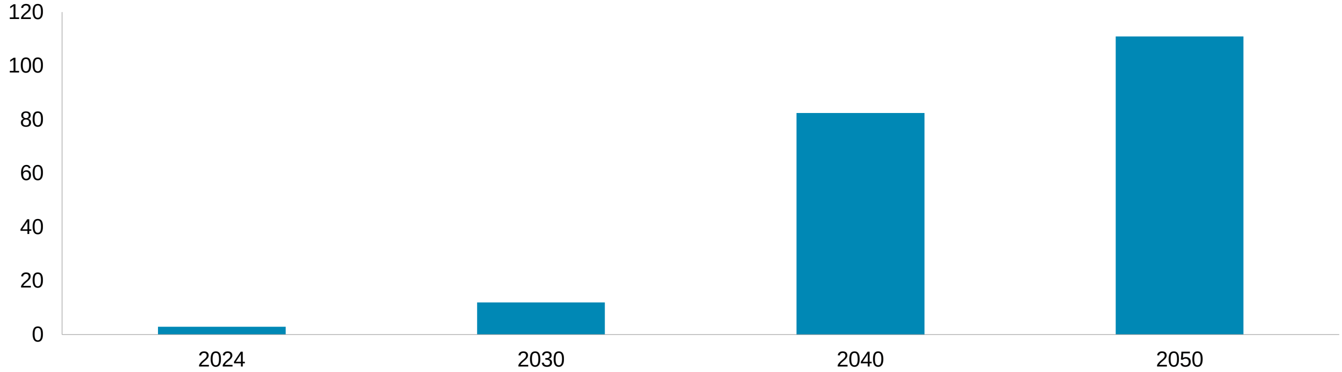
Table 6.5: Electrolyser efficiency outlook

	Electrolyser efficiency evolution, HHV
2025	75%
2030	78%
2040	81%
2050	81%

Note: 2025 efficiencies are vetted by OEMs and developers. We ramp up close to the theoretical maximum by 2050. Long-term also assumes penetration of solid oxide electrolysis cell electrolysers by SPGCI, which run at a much higher electrical efficiency (>85% LHV).

From the total green renewable electricity available, the above electrolyzer efficiency evolution is used over the horizon of 2024 – 2050 to calculate the total RFNBO green hydrogen generation potential. As a result, Total RFNBO green hydrogen generation in the EU+ is expected be approximately 111 MMtoe.

Figure 6.16 – Total RFNBO Green hydrogen generation, EU+ (MMtoe)



Source: S&P Global Commodity Insights.

The overall demand of RFNBO was determined by evaluating the requirements of the industrial sector, power sector, refinery use and transport sector. In Max Electron, the total demand of RFNBO is 164 MMtoe, while in More Molecule it is 181 MMtoe. In Max Electron, the demand of non-E-Fuel RFNBO is 151 MMtoe, while in More Molecule it is 160 MMtoe, as a result of the additional green hydrogen required for refinery supply and increased direct use in the transport sector.

6.4 E-fuels supply

Based on market insights, SPGCI identifies that short term e-fuels projects (firm and 25% of speculative) will add a cumulative capacity of ~287 ktoe in 2030 for the EU+.

Table 6.6: E-fuels projects

Region	Country	Status	Thousand metric ton per year, 2030
Europe	Denmark	Speculative	90
Europe	France	Speculative	150
Europe	Germany	Speculative	413
Europe	Netherlands	Speculative	50
Europe	Norway	Speculative	78
Europe	Norway	Speculative	99
Europe	Portugal	Speculative	80
Europe	Spain	Firm	2
Europe	Spain	Speculative	20
Europe	Sweden	Speculative	50
Europe	United Kingdom	Speculative	107

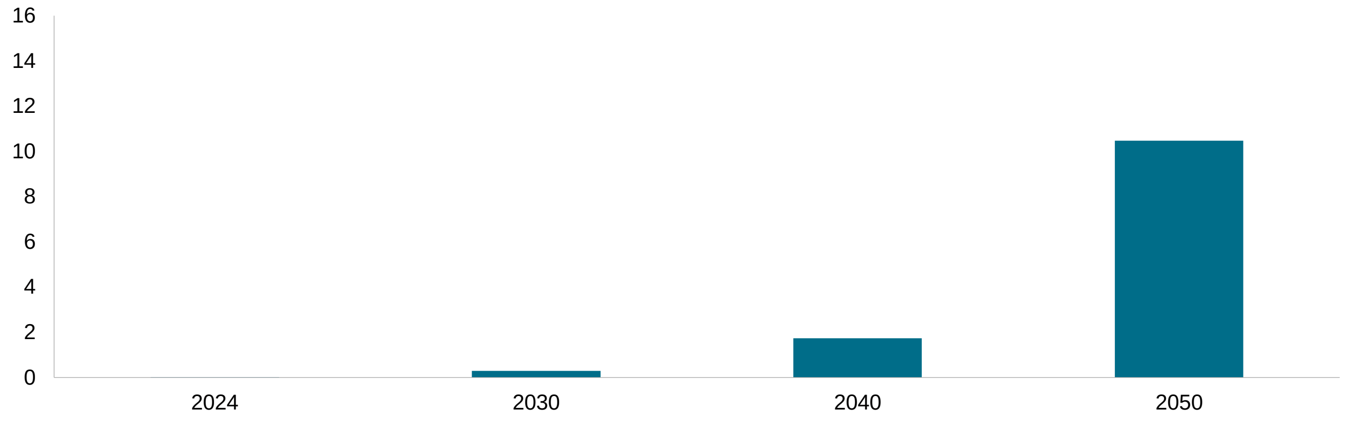
Note: E-fuels include E-SAF, E-Gasoline and E-Diesel

E-fuels capacity supply forecast for 2030 is based on the short-term capacity data in 2030 from firm and 25% of speculative e-fuels projects in the EU+.

Concerning the forecast for the 2030-2050 period, the capacity forecast increase after 2030 is based on the increasing green hydrogen generation available for the transport sector in the EU+. The green hydrogen generation available for the transport sector is the balance remaining after the total green hydrogen generation mentioned in Section 6.3 is supplied to the industry sector to achieve the green hydrogen targets i.e. 42% at 2030, 80% at 2040 and 100% at 2050, plus the green hydrogen refinery supply requirement as per the LP modelling. The available green hydrogen for the transport sector in the EU+ acts as a cap to forecast the E-fuels capacity in the long term.

The capacity forecast is then assumed to increase with compounded annual growth rate (CAGR = $((Capacity_{2050}-Capacity_{2030})/Capacity_{2030})^{(1/years)}-1$) from 2030 to 2050 for E-fuels in the EU+ of 20% for Max Electron, while looking at the cap of green hydrogen available for the transport sector. In our assumptions we assume that domestic green hydrogen generation in EU for the transport sector will be prioritized for direct and derivative uses of green hydrogen in 2050 in the EU+ over e-fuels production, i.e. e-SAF, e-gasoline and e-diesel.

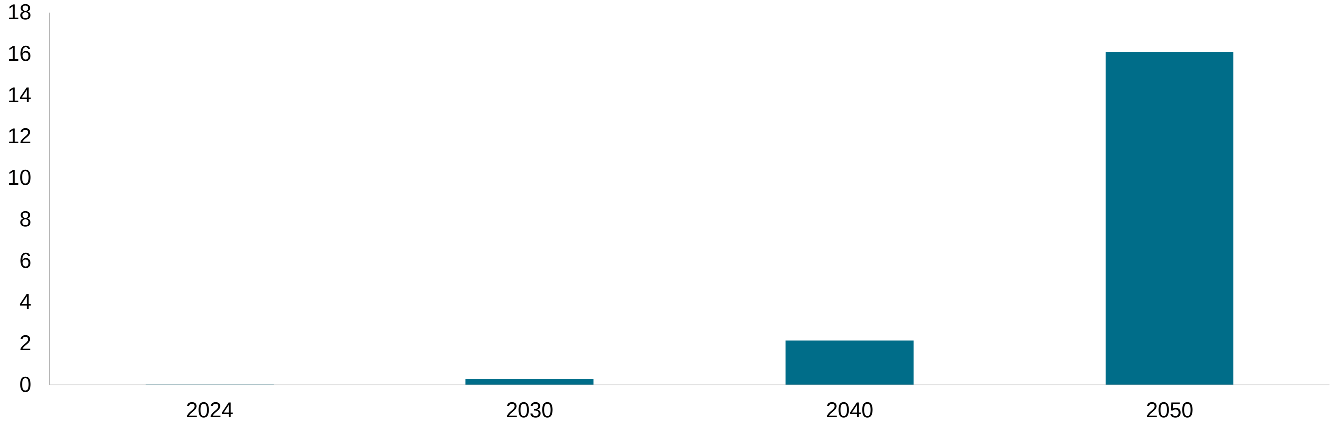
Figure 6.17 – Max Electron EU+ e-fuels capacity forecast (MMtoe)



Source: S&P Global Commodity Insights.

For the More Molecule supply forecast the same methodology is used, however the capacity forecast is then assumed to increase with compounded annual growth rate of ~22% from 2030 to 2050 for E-fuels in the EU+, while looking at the cap of green hydrogen available for the transport sector. In More Molecule, it is assumed that additional green hydrogen supply and electricity will be required for the transportation sector, while meeting the demands from the other sectors.

Figure 6.18 – More Molecule EU+ e-fuels capacity forecast (MMtoe)



Source: S&P Global Commodity Insights.

7 Security of Supply

7.1 Conventional Hydrocarbon

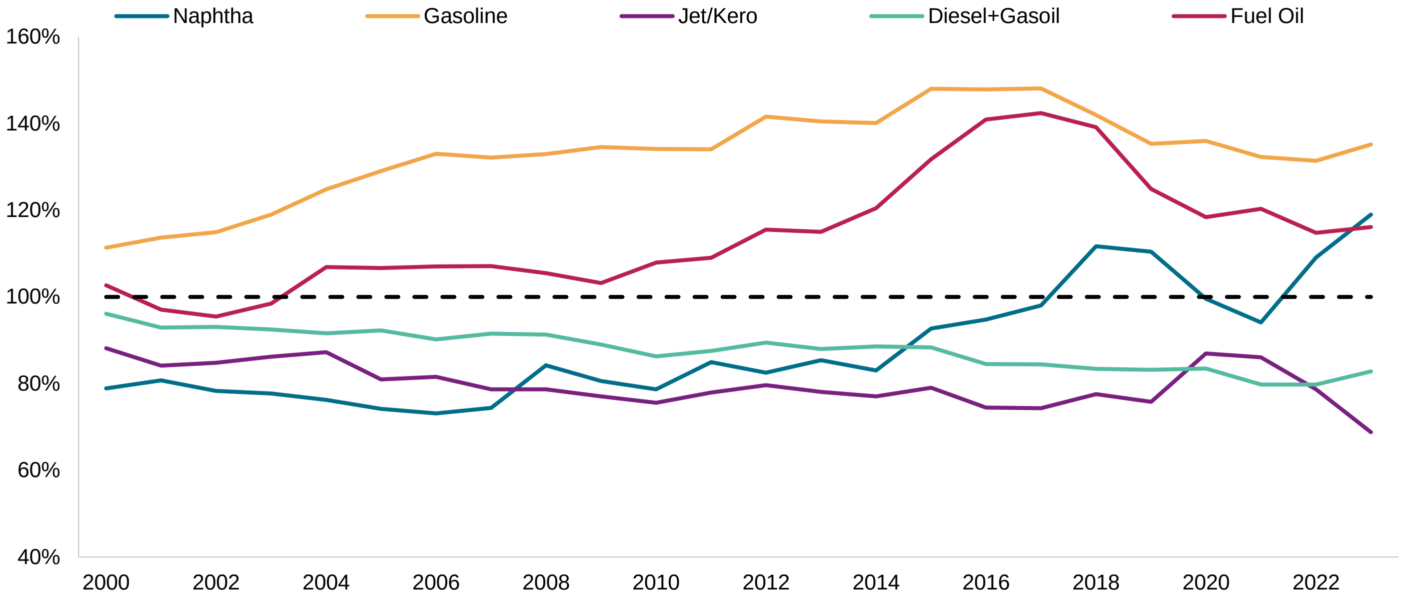
Analysis of security of supply for conventional hydrocarbon centers around availability of crude oil as feedstock for refinery processing and the capability of refineries to process the crude and produce the products that the market requires. The EU+ imports the majority of its crude feedstock today. Conventional hydrocarbons have historically made up the vast majority of liquid fuel supply, but in this study as we move into the future other liquid fuel sources (biofuels and RNFNBOs) become increasingly important.

One useful measure of security of supply is Refining Cover, where for any refined product

Refining Cover % = 100 * (Production of Product / Demand for Product)

Looking at historical data for the EU+ allows us a basis for comparison with future projections.

Figure 7.1 – Historical Main Fuels Refining Cover % for EU+



Source: S&P Global Commodity Insights.

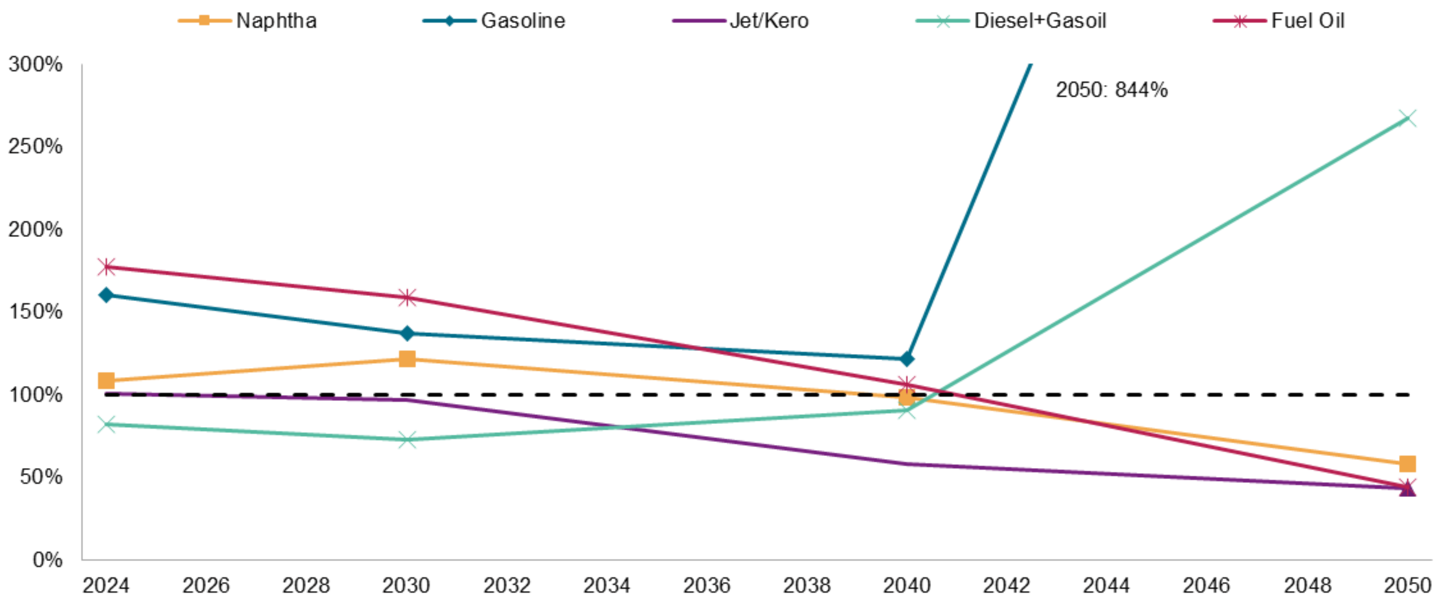
It can be seen that Europe has long had an excess of supply of conventional gasoline and fuel oil (refining cover greater than 100%) but a shortage of conventional diesel+gasoil and jet/kero. Refining cover for these has reduced from 96% and 88% respectively in 2000 to 83% and 69% respectively in 2023. Naphtha has moved from a position of shortage (refining cover 79% in 2000) to surplus (refining cover 119% in 2023).

The current exposure to imports to balance demand is a potential risk for middle distillates (diesel, jet, gasoil), as supply of these products is currently the most vulnerable part of the European main fuels supply chain. It has however never materialized into real concern in the last 30 years, thanks to the liquidity of international crude oil and products markets.

In both Max Electron and More Molecule, the EU+ demand for conventional hydrocarbons falls and the region enters a sustained period of having an excess of refining capacity. The scenario economics also favour jet production over diesel/gasoil. However generally poor refining economics restricts the operating rate of conventional refineries and as a result the forecast refining cover for most fuels falls over 2024 to 2040.

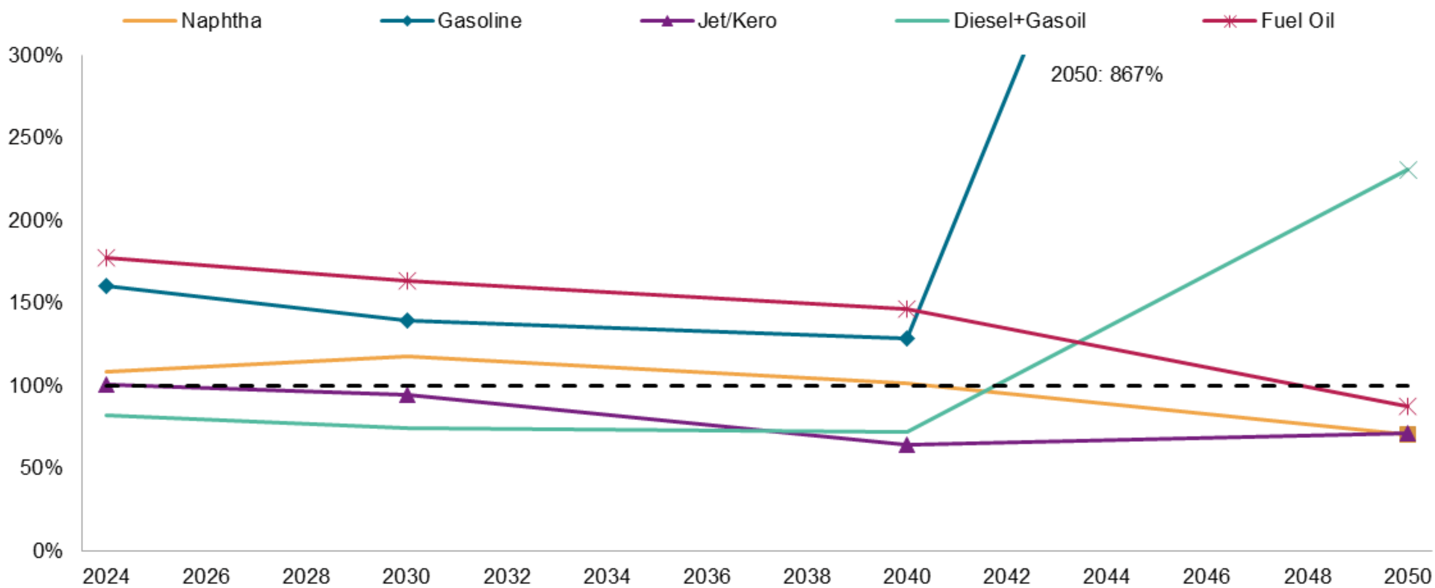
It is after 2040 when the rationalization of refineries results in refining cover for naphtha, LPG, jet/kero and fuel oil falling below 100% (albeit for much smaller demand volumes than in 2024-2040). By 2050 the very low European demand for fossil gasoline and diesel results in very high refining cover for these fuels, even though volumes produced are small – in 2050 Max Electron gasoline production is 4.9 million tonnes, More Molecule gasoline production is 6.3 million tonnes, compared with 140 million tonnes in 2024.

Figure 7.2 – Forecast Main Fuels Refining Cover % for EU+, Max Electron



Source: S&P Global Commodity Insights.

Figure 7.3 – Forecast Main Fuels Refining Cover % for EU+, More Molecule



Source: S&P Global Commodity Insights.
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It can be concluded that EU+ security of supply for fossil hydrocarbons remains similar to that seen in 2024 out to 2040, with a local surplus of gasoline, fuel oil and naphtha, but short of diesel and jet. Post 2040 the very low demand for fossil gasoline and diesel results in a very large refining cover for these fuels.

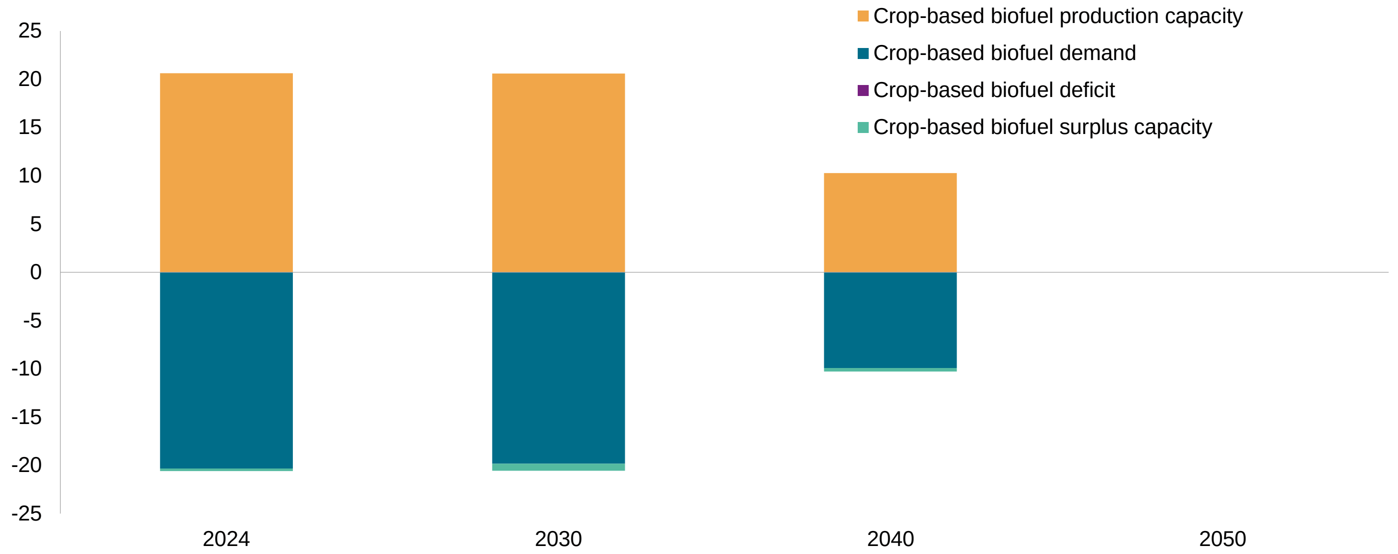
For naphtha, LPG, jet and fuel oil however the refinery rationalization out-paces demand reduction and refining cover reduces below 100%. Of most concern would be naphtha where naphtha demand for petrochemicals remains but conventional refining capacity is no longer able to supply the demand, resulting in refining cover of 58% in Max Electron and 70% in More Molecule. However, co-production of bio-naphtha when producing biodiesel and biojet helps to reduce this deficit. For LPG co-production of bio-LPG also helps reduce the refined product deficit, however LPG supply benefits from production from off-shore oil and gas production and stabilization – a non-refining source of product.

7.2 Biofuels

After establishing the supply profiles for the low carbon fuels, the EU+ and country balances were produced to establish the security of supply analysis by comparing the supply and demand forecasts.

In both the Max Electron and More Molecule scenarios, food and feed crop-based biofuel demand and hence supply declines to zero to meet the GHG reduction targets by 2050.

Figure 7.4 – Max Electron EU+ Food and Feed Crop-based biofuel balance (MMtoe)



Source: S&P Global Commodity Insights.
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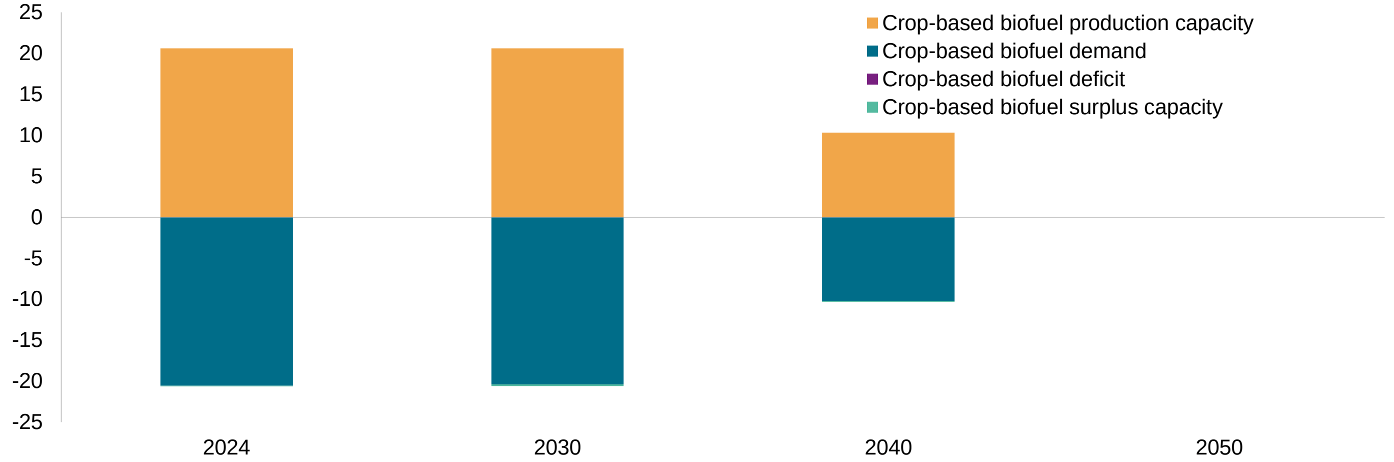
Figure 7.5 – More Molecule EU+ Food and Feed Crop-based biofuel balance (MMtoe)



Source: S&P Global Commodity Insights.
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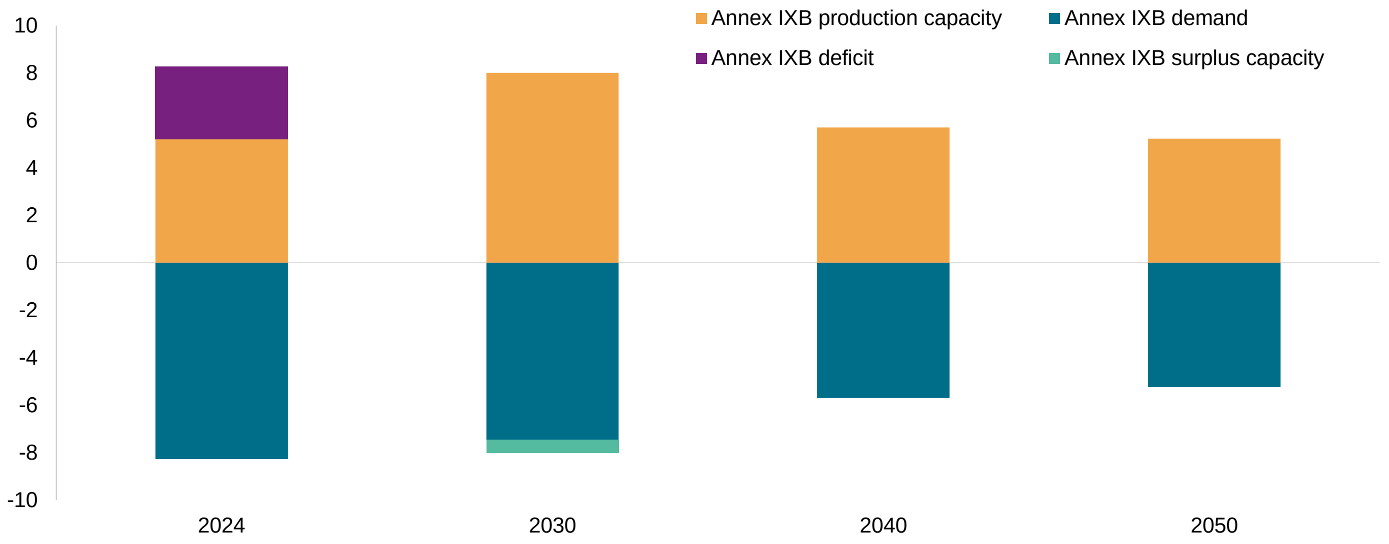
Similarly to food and feed crop-based biofuel EU+ supply, SPGCI expects Annex IXB EU+ supply to decline in the long-term forecast in line with the decreasing demand trend. Under Max Electron, Annex IXB biofuel demand declines to 5.24 MMtoe in 2050 compared to 5.72 MMtoe under More Molecule.

Figure 7.6 – Max Electron EU+ Annex IXB biofuel balance (MMtoe)



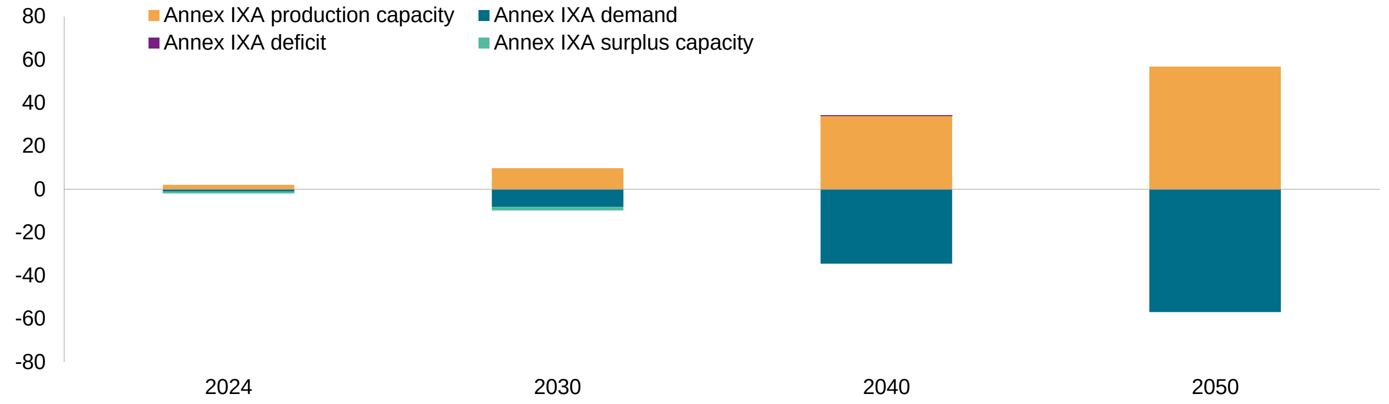
Source: S&P Global Commodity Insights.

Figure 7.7 – More Molecule EU+ Annex IXB biofuel balance (MMtoe)

Source: S&P Global Commodity Insights.

In regard to Annex IXA biofuels, under More Molecule, there is a greater demand for liquid biofuels and so the supply requirements for Annex IXA biofuels is larger than in Max Electron. In Max Electron, Annex IXA biofuel demand increases to 56.90 MMtoe in 2050 compared to 88.15 MMtoe in More Molecule. This means that there is a greater need for mobilizing advanced biofuel feedstocks through improved farming practices and improved R&I within the EU to meet the demand under More Molecule.

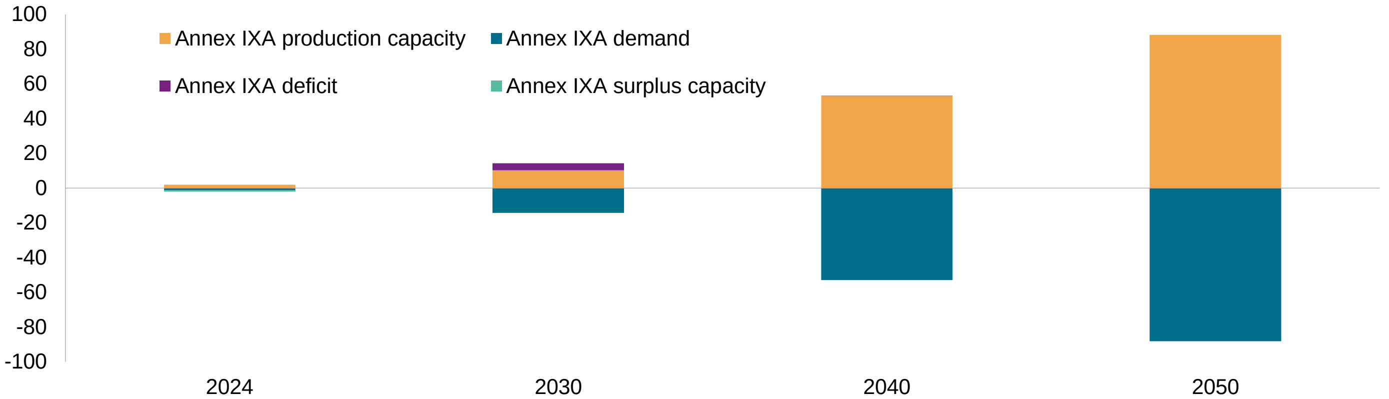
Figure 7.8 – Max Electron EU+ Annex IXA biofuel balance (MMtoe)



Source: S&P Global Commodity Insights.

Under More Molecule, there is higher demand for liquid biofuels and so the supply requirement for Annex IXA biofuels is greater than in Max Electron.

Figure 7.9 – More Molecule EU+ Annex IXA biofuel balance (MMtoe)



Source: S&P Global Commodity Insights.

The EU+ will require a substantial volume of biofuel production capacity by 2050 to meet demand and these bio refineries will need to be distributed across the EU+ region to remain relatively close to the bio-feedstock source, as it does not make sense to transport large volumes of low energy density biomass across long distances.

The increase in demand for advanced biofuels co-incides with reduction in demand for fossil fuels. Given the wide distribution requirement for new bio-fuel plant there is significant potential for existing hydrocarbon refineries to move to processing of bio-feedstocks, particularly in countries where there is a high availability of advanced bio feedstocks.

It can be seen in Section 5 that in our scenarios, utilization of (fossil) Diesel Hydrotreating capacity falls from 72% in 2024 to 49% in Max Electron and 40% in More Molecule. (More Molecule has higher remaining DHT capacity and this results in lower utilization). As the fossil hydrotreating capacity becomes available, refiners will have the option to convert existing plant into stand-alone bio-fuel processing plant. This would likely reduce overall investment costs as the re-purposed plant could take advantage of existing process equipment and supporting infrastructure on the existing refinery site and the biofuels produced would have access to the already existing fuel distribution networks.

Our analysis calculated the volume of biofuels produced by co-processing with fossil fuel on operational refineries. Where refinery diesel/kerosene hydrotreating utilization falls below 80%, we then allocate this spare operational capacity to be used for co-processing or stand-alone (batch mode) biofuel processing. When under our analysis fossil refining capacity is shutdown, we allow part of the shutdown refineries to be modified to a new biofuel plant, in order to reduce the investment needed. These stand-alone plants are defined as “new” biofuel capacity. Biofuel plant capacities refer to the total production of bio-diesel, bio-gasoline and bio-jet, with an average biofuel plant capacity of 1 MMTPA assumed. These plants also co-produce bio-Naphtha, bio-LPG and bio-base oil, depending on the specific technology. The analysis of EU+ biofuel processing capacity location across the EU+ for both scenarios is shown in Figures 7.28 to 7.33.

By 2050 the EU+ would need 22 MMTPA of re-purposed or new biofuel capacity in the Max Electron Scenario, and 48 MMTPA of re-purposed or new biofuel capacity in the More Molecule Scenario. Assuming a standard biorefinery of 1MMTPA of capacity, by 2050 the EU+ would require 22 new biorefineries in Max Electron and 48 in More Molecule. This is in addition to the bio-coprocessing and pure bio-processing capacity on any remaining operational conventional refineries.

In both scenarios, the EU+ requirement for biofuels and hence requirement for bio-feedstocks can be met by indigenous biofeedstock production – meaning that if the investment required to collect and process these feedstocks is put in place, the EU+ would not need to import biofuels (or biofeedstocks) to cover the demand. Such a position would enhance EU+ fuel security.

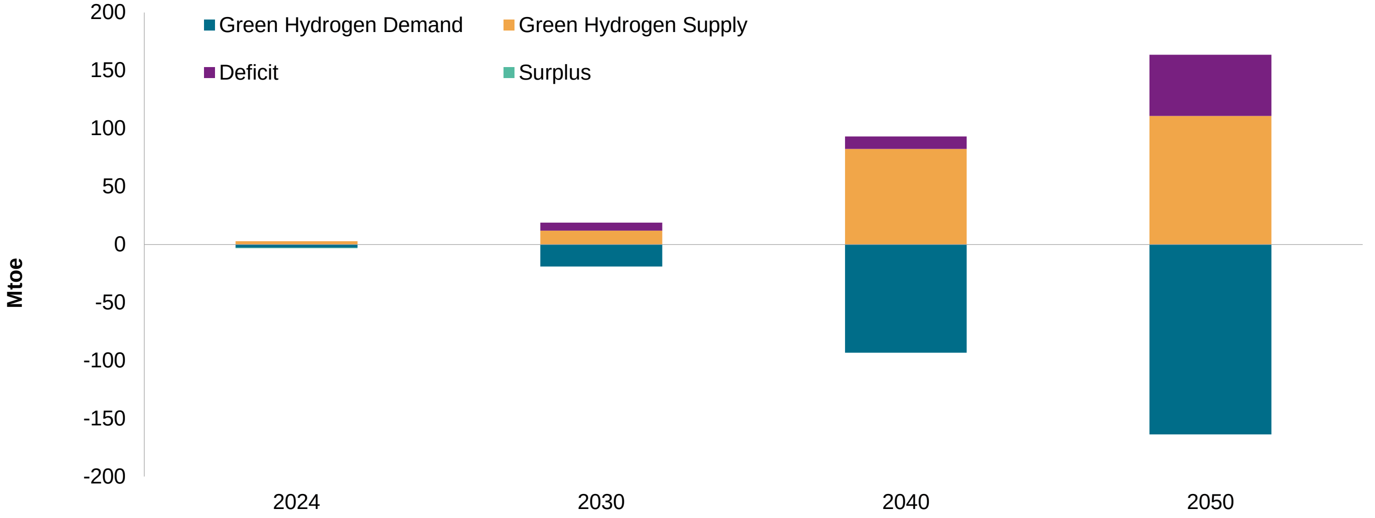
7.3 Renewable Fuels of Non Biological Origin (RFNBO)

RFNBO demand will be coming from the hard to abate sectors such as industrial, power, refinery use and transport. Overall, the EU+ industrial hydrogen demand for RFNBOs will be based on the target defined by the EU i.e., 42% by 2030 and an assumed 100% by 2050 of overall industrial hydrogen demand (excluding by-product hydrogen production from processes such as reforming and steam cracking which must be consumed). Demand in the transport sector will be coming from direct hydrogen use by ICE and FCEV fleet and from the use of hydrogen to produce e-fuels.

Given the expected maximum possible renewable power capacity by 2050 under the SPGCI Green Rules scenario mentioned in section 6.3 and with strong demand for renewable power coming from power, transport and other sectors, the EU+ would have limited renewable power capacity available to manufacture the expected overall RFNBO demand.

In Max Electron, overall deficit of RFNBOs for the EU+ increases to 32% of the total RFNBO demand in 2050. Deficit volumes can either be coming to the EU+ as green hydrogen molecules or synthetic fuel molecules, although it is likely to be easier and more cost effective to transport finished e-fuels rather than hydrogen.

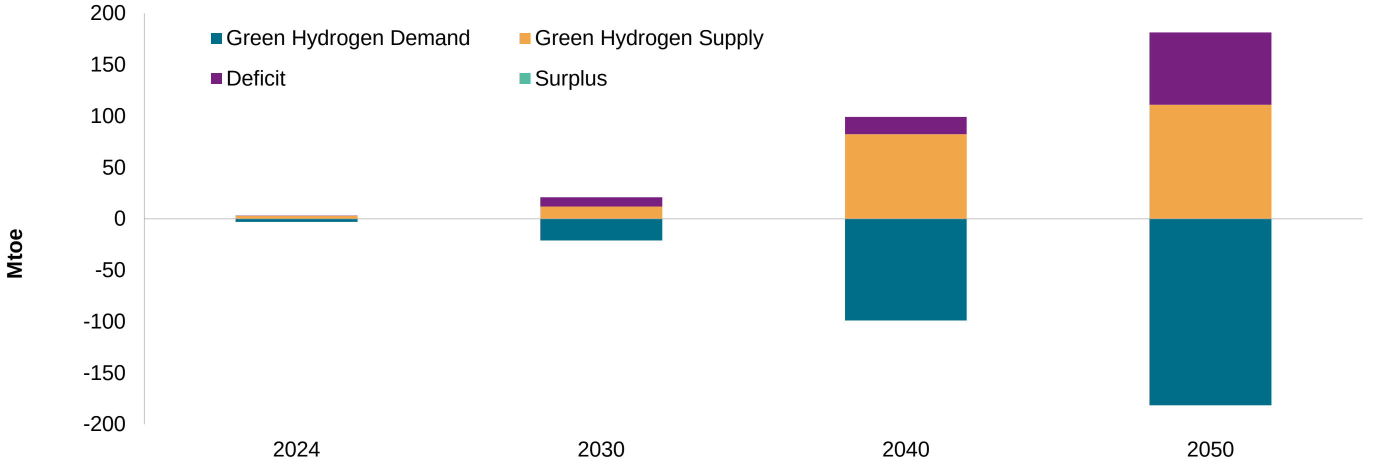
Figure 7.10 – Max Electron EU+ green hydrogen supply demand balance (MMtoe)



Source: S&P Global Commodity Insights.

In More Molecule, overall deficit of RFNBOs for the EU+ increase to 39% of the total RFNBO demand in 2050.

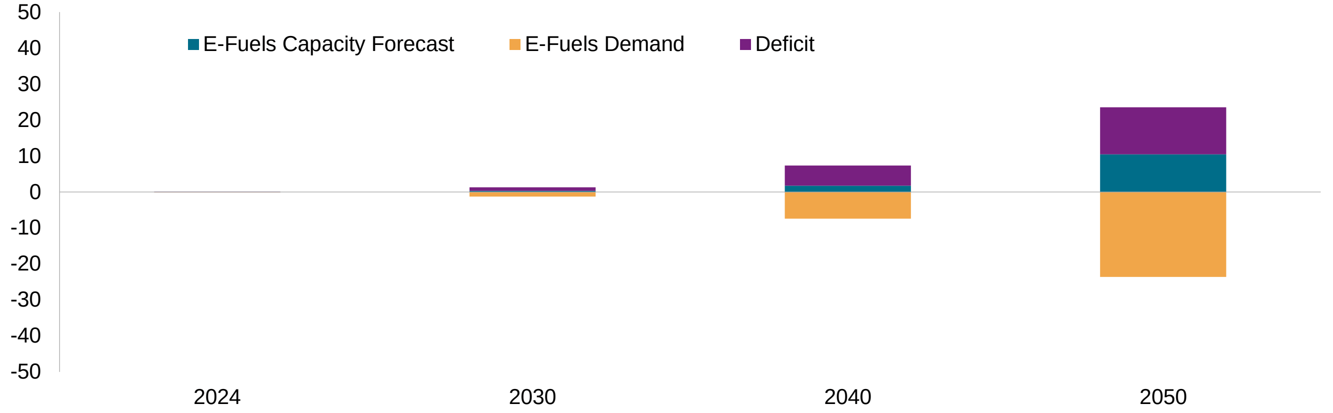
Figure 7.11 – More Molecule EU+ green hydrogen supply demand balance (MMtoe)



Source: S&P Global Commodity Insights.

In Max Electron, overall deficit of e-fuels for the EU+ increases to 56% of the total e-fuels demand in 2050.

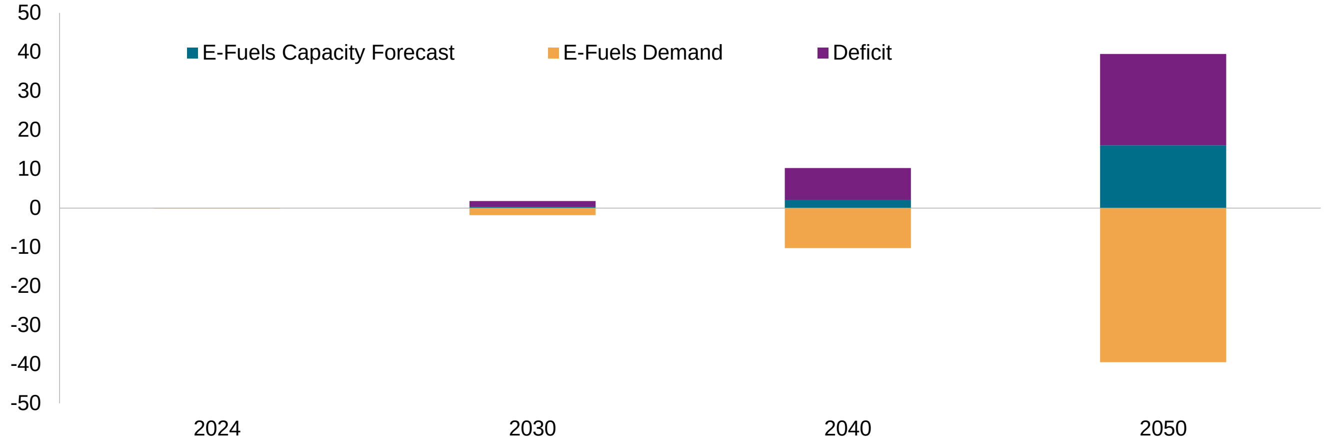
Figure 7.12 – Max Electron EU+ e-fuels supply demand balance (MMtoe)



Source: S&P Global Commodity Insights.

In More Molecule, overall deficit of e-fuels for the EU+ increases to 59% of the total e-fuels demand in 2050.

Figure 7.13 – More Molecule EU+ e-fuels supply demand balance (MMtoe)



Source: S&P Global Commodity Insights.

Regarding e-fuels production, if we assume a standard e-fuel plant capacity of 1 million tonnes per year, in Max Electron, by 2050 the number of e-fuels plants required would be 11 for the EU+. In More Molecule, the number of e-fuels plants required would be 17 for the EU+.

Overall, the EU+ region deficit requirements for RFNBOs and e-fuels, will increase with time. Supply is expected to be mostly coming from regions with a lower cost of production such as North Africa, the Middle East, Chile or the US Gulf Cost. Import of e-fuels could happen either as finished products or as e-crude to be refined in EU refineries, depending on the business model of the international e-fuel producers.

Within Europe the location of plants within the EU+ will be more inclined towards areas with cheaper potential renewable electricity, i.e. cheaper green hydrogen, plus in locations supported by national government policies. This is likely to mean European production will be skewed towards southern European countries where there is significantly more potential for production of renewable solar power.

Table 7.1: European renewable power mix

EU+ regions	Capacity factor/utilisation rate 65%, LCOE $/MW	Renewable mix
Germany	60	Wind = 60%, solar = 40%
France	37	Wind = 50%, solar = 50%
Spain	26	Wind: 40%, solar = 60%

Note: Over build factor = 3
LCOE = levelized cost of electricity

In both scenarios there will be a significant need to import green molecules to the EU+ region. Green molecules imported as green hydrogen, or e-fuels require development of transportation infrastructure. Multiple hydrogen carriers exist (e.g. hydrogen gas, ammonia, etc.), each with different transportation economics, but still relatively high costs, and with safety concerns. In the longer term, with reduction in the overall production cost of e-fuels in regions with low overall green electricity cost and surplus supply, the liquid e-fuels can be a key source of green molecules import in the EU+.

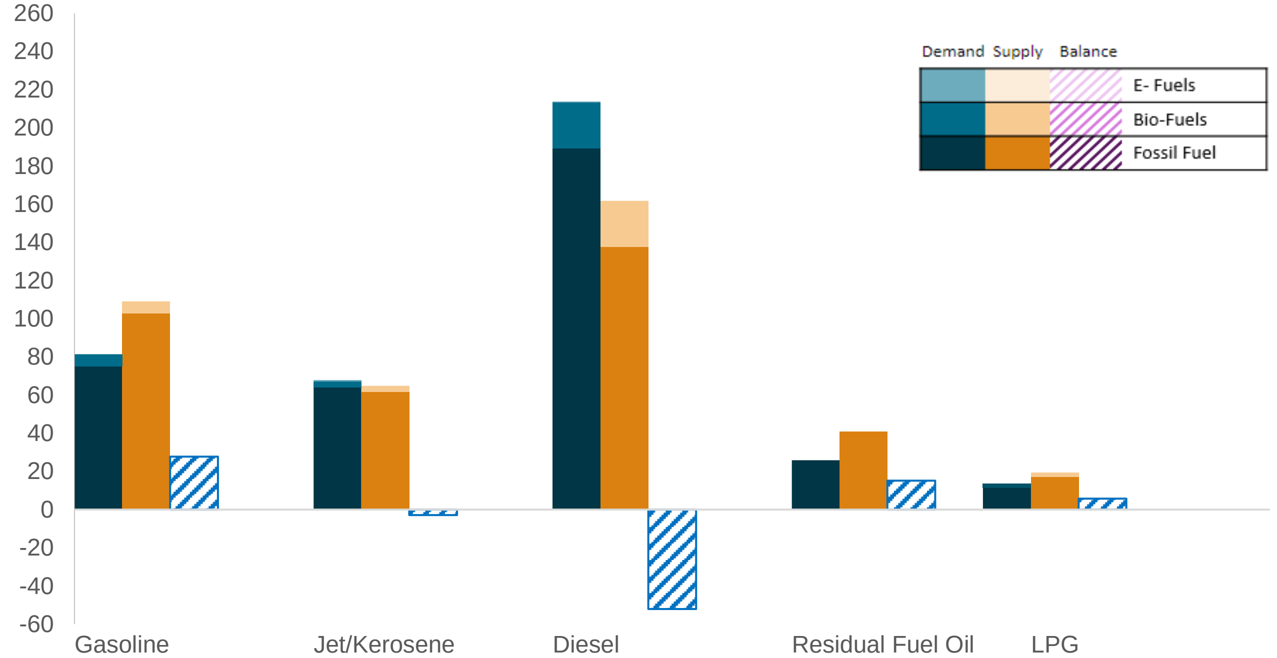
7.4 Total Liquid Fuels Supply Demand Balance

For these supply demand balances, bio-fuel supply always equals bio-fuel demand – our logic being that EU+ has enough biofeedstock to meet the demand, but would be unlikely to move to a structural export position. E-fuel supply is limited as described in Section 7.3 and so does not meet e-fuel demand, and the e-fuel balance must be obtained by imports. Conventional hydrocarbon demand is limited by the emissions level needed to be achieved in any year, and the difference between this demand and the available refinery production is then balanced by imports or exports.

The charts show for each fuel/product, the EU+ demand of fossil, bio, and e- product, the EU+ supply of fossil, bio, and e- product, and the net balance.

Figures 7.14 through to 7.19 show the total supply demand balances for fossil, bio, and e- fuels for the EU+ countries for all years (2030, 2040, 2050) for Max Electron and More Molecule.

Figure 7.14 – 2030 EU+ fossil fuels, biofuels and e-fuels balance, Max Electron (MMtoe)



Source: S&P Global Commodity Insights
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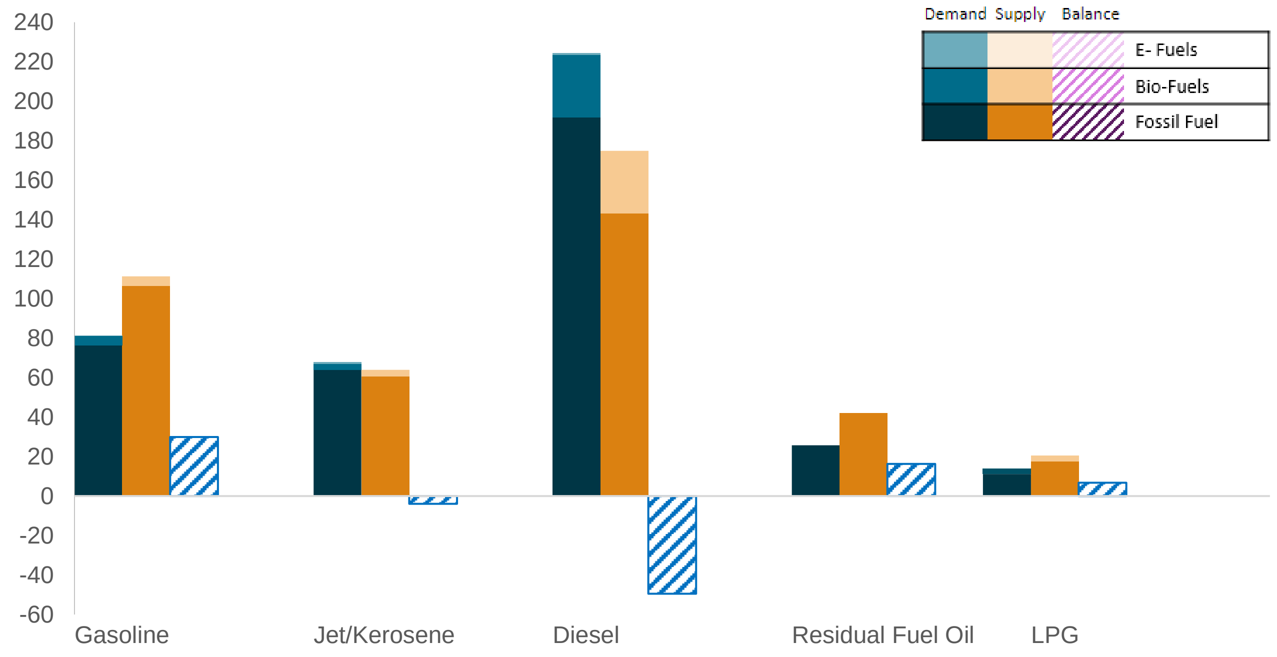
Figure 7.15 – 2030 EU+ fossil fuels, biofuels and e-fuels balance, More Molecule (MMtoe)



Source: S&P Global Commodity Insights
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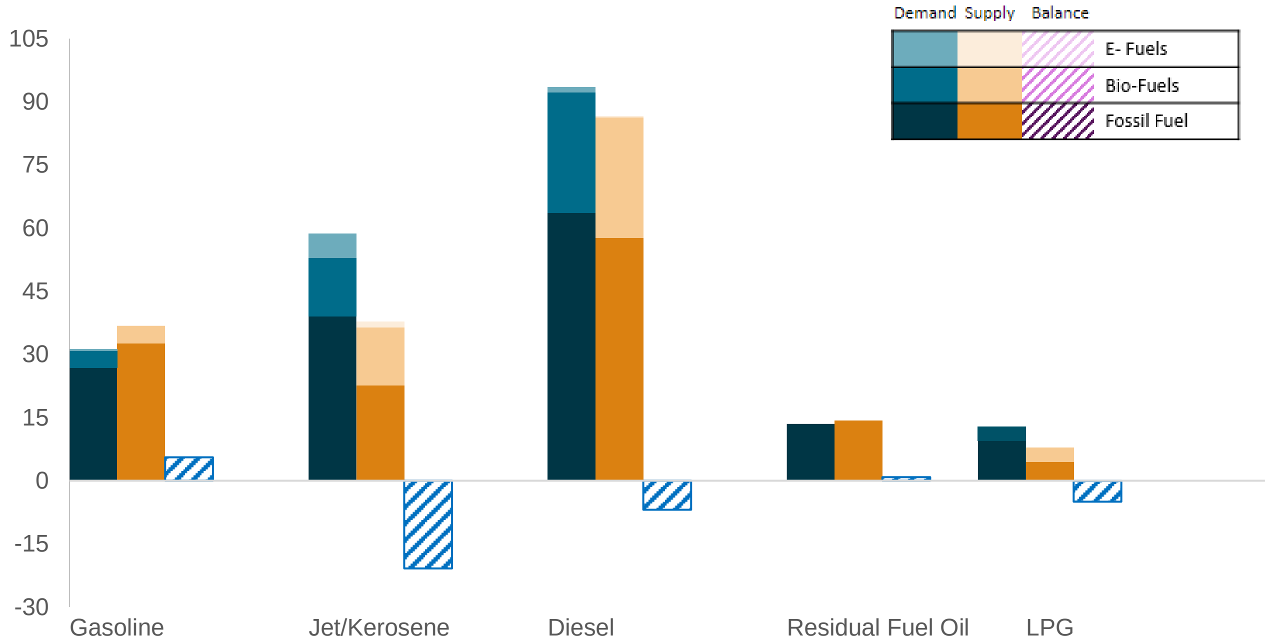
For 2030 in both scenarios the EU+ retains a similar supply/demand profile to 2024, with a surplus of gasoline, deficit of middle distillates (diesel + kerosene) and small surplus of fuel oil.

Figure 7.16 – 2040 EU+ fossil fuels, biofuels and e-fuels balance, Max Electron (MMtoe)



Source: S&P Global Commodity Insights
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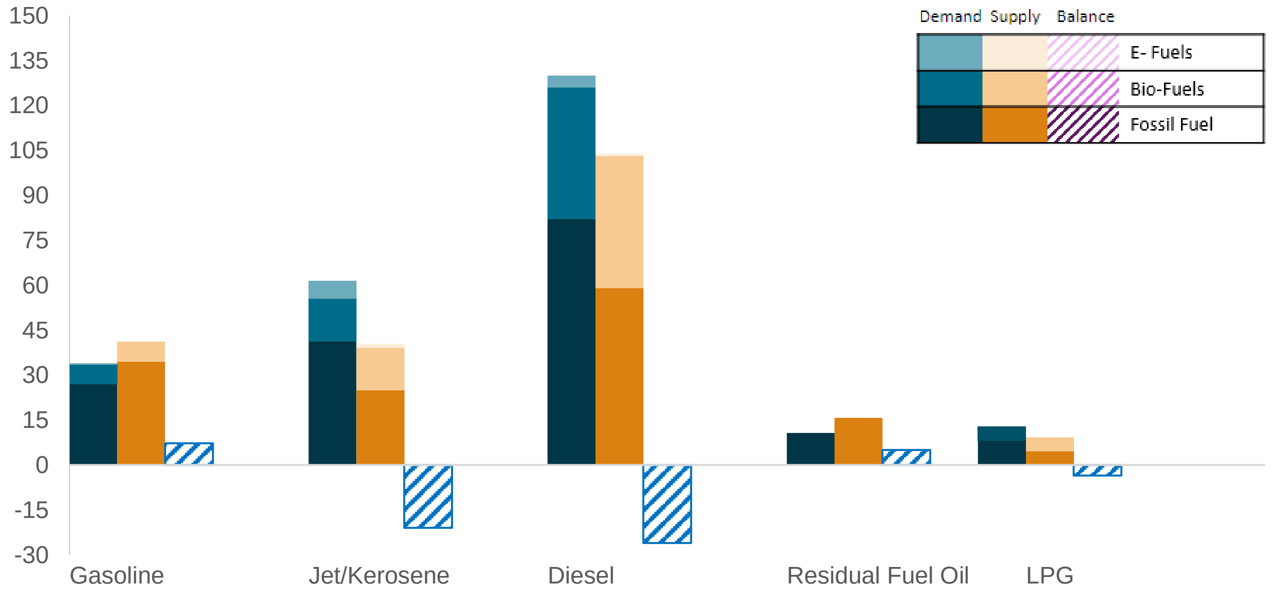
Figure 7.17 – 2040 EU+ fossil fuels, biofuels and e-fuels balance, More Molecule



Source: S&P Global Commodity Insights
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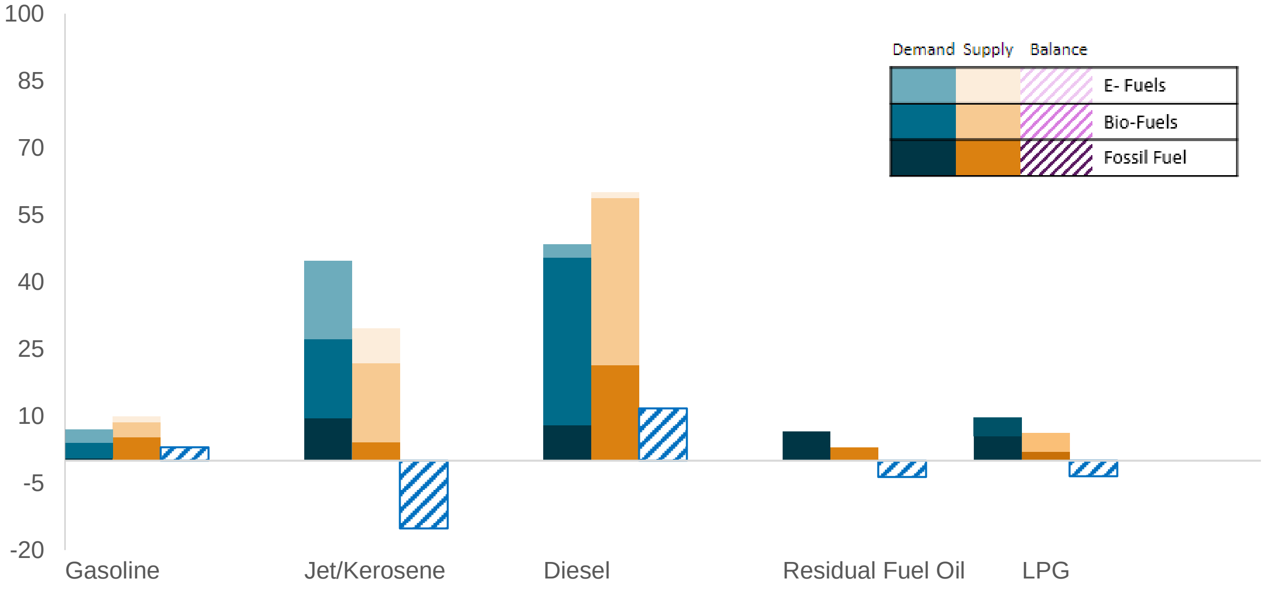
By 2040 the absolute surplus/deficit volumes are reducing, due to the reduction in both EU+ liquid fuels demand and supply. Both scenarios show a deficit of jet/kerosene and diesel, mainly due to remaining fossil middle distillate demand outstripping remaining fossil distillate supply. Gasoline remains with a small surplus in both scenarios.

Figure 7.18 – 2050 EU+ fossil fuels, biofuels and e-fuels balance, Max Electron



Source: S&P Global Commodity Insights
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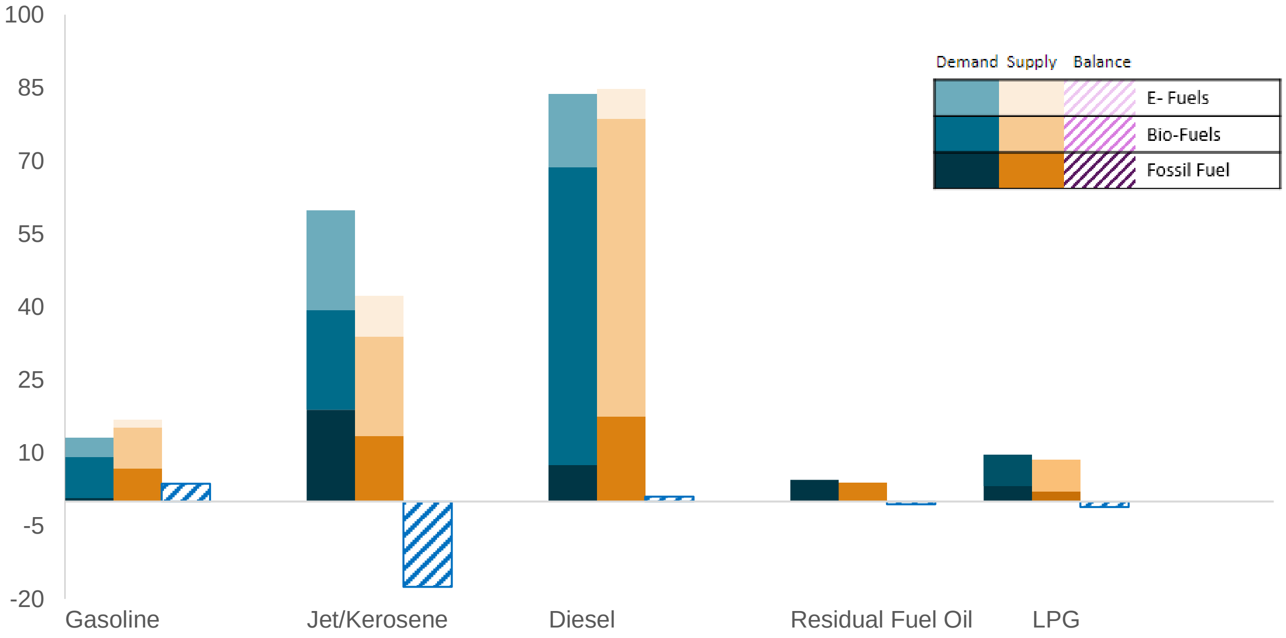
Figure 7.19 – 2050 EU+ fossil fuels, biofuels and e-fuels balance, More Molecule (MMtoe)



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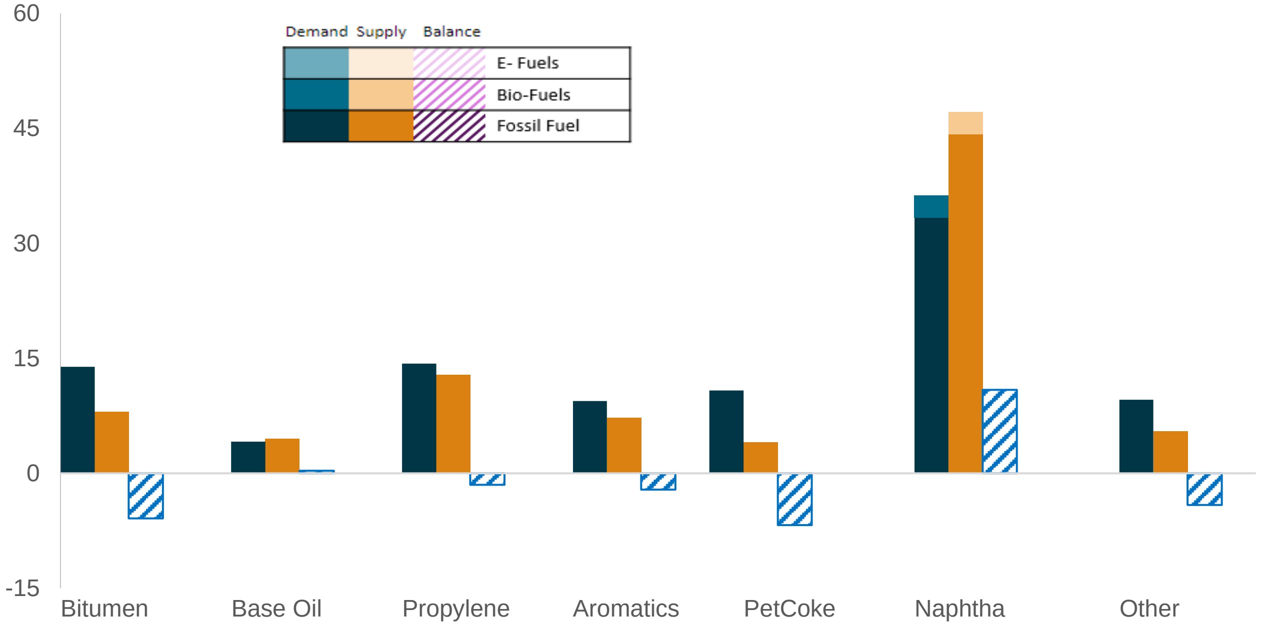
By 2050 the surplus/deficit absolute volumes have reduced further. The drop in demand for fossil diesel results in modest surplus of diesel in the Max Electron scenario and near balance in the More Molecule scenario. In both scenarios a significant deficit of jet/kerosene remains.

Figures 7.14 to 7.18 clearly show the progression from fossil fuels being the most significant supply in 2024 to a combination of biofuels and e-fuels becoming the most significant supply in 2050 under both scenarios.

7.5 Total Other Products Supply Demand Balance

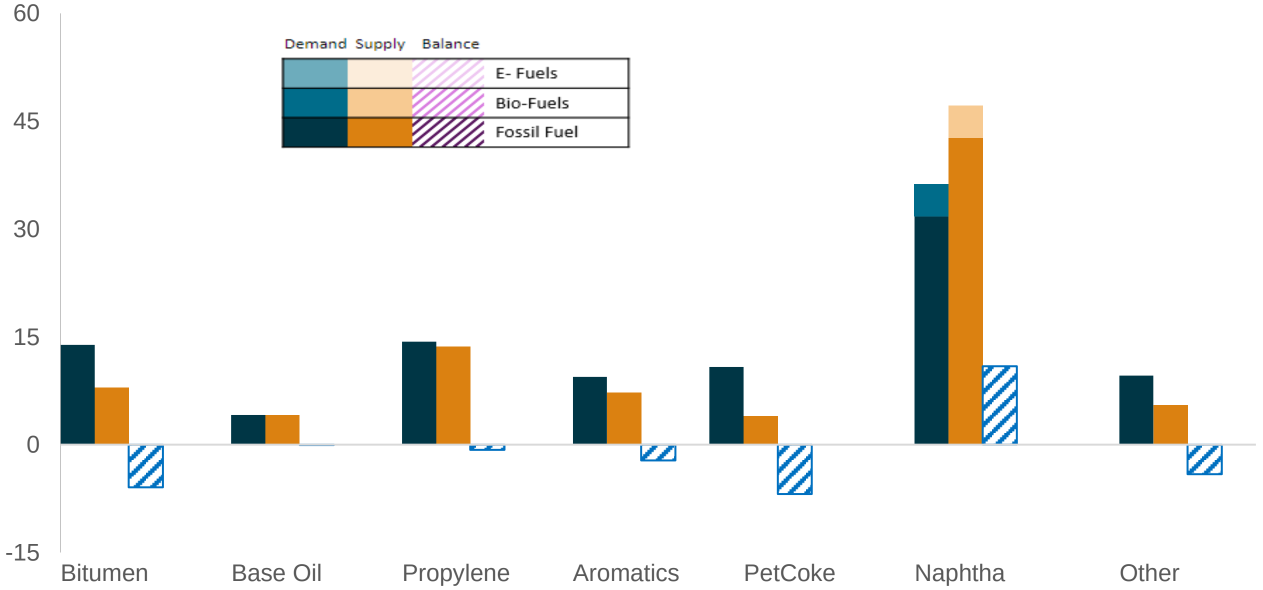
Figures 7.20 through to 7.25 show the total supply demand balances for fossil, bio, and e- non-fuel products for the EU+ countries for 2030, 2040 and 2050 for Max Electron and More Molecule scenarios.

Figure 7.20 – 2030 EU+ fossil, bio and e- non-fuels balance, Max Electron (MMtoe)



Source: S&P Global Commodity Insights

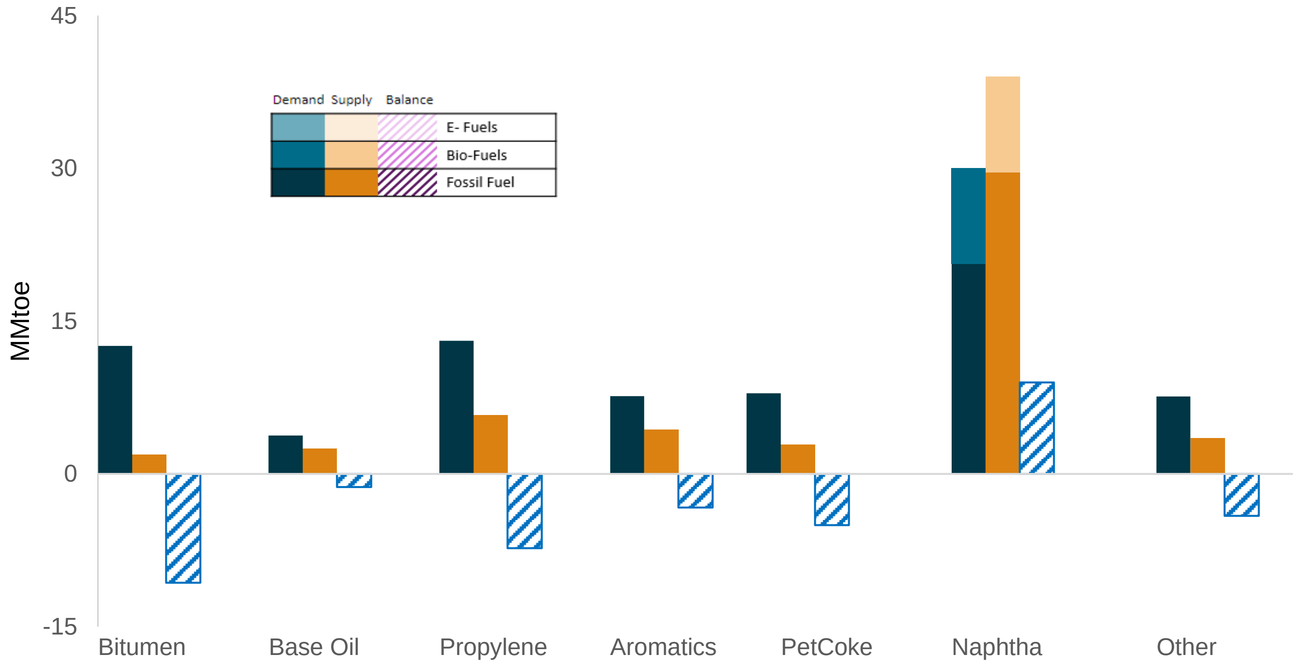
Figure 7.21 – 2030 EU+ fossil, bio and e- non-fuels balance, More Molecule (MMtoe)



Source: S&P Global Commodity Insights

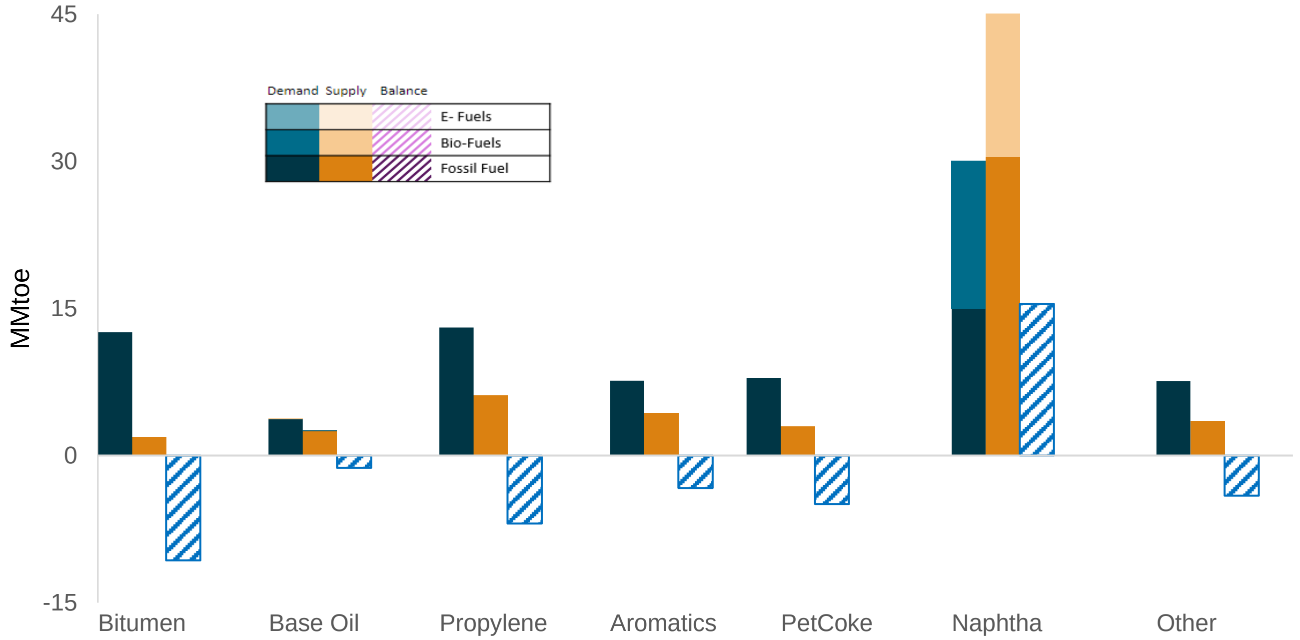
By 2030 the EU+ is expected to have a deficit of Bitumen and Petcoke, and a surplus of Naphtha. For these non-fuel products there is little difference in balances between the two scenarios.

Figure 7.22 – 2040 EU+ fossil, bio and e- non-fuels balance, Max Electron (MMtoe)



Source: S&P Global Commodity Insights

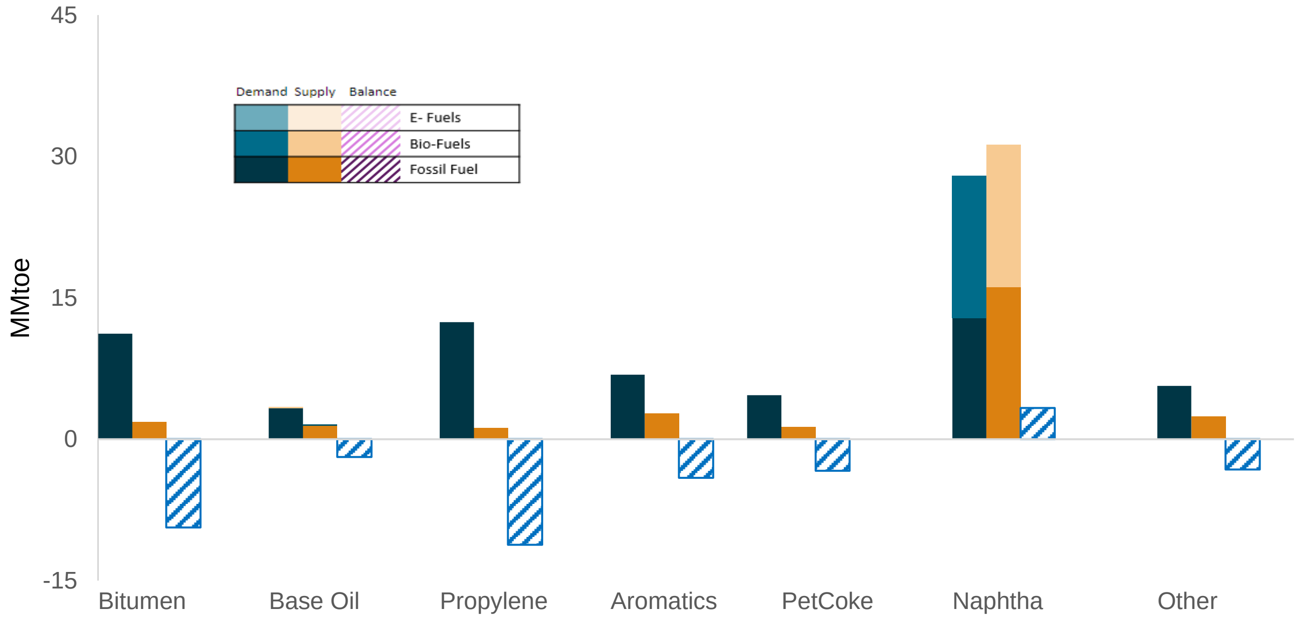
Figure 7.23 – 2040 EU+ fossil, bio and e- non-fuels balance, More Molecule (MMtoe)



Source: S&P Global Commodity Insights

By 2040 the EU+ has a deficit of bitumen, propylene, aromatics, and petcoke, and a surplus of naphtha in both scenarios. The deficits of bitumen, propylene and aromatics are increased over 2030 levels. The naphtha surplus in the More Molecule scenario is now greater than in the Max Electron scenario.

Figure 7.24 – 2050 EU+ fossil, bio and e- non-fuels balance, Max Electron (MMtoe)



Source: S&P Global Commodity Insights
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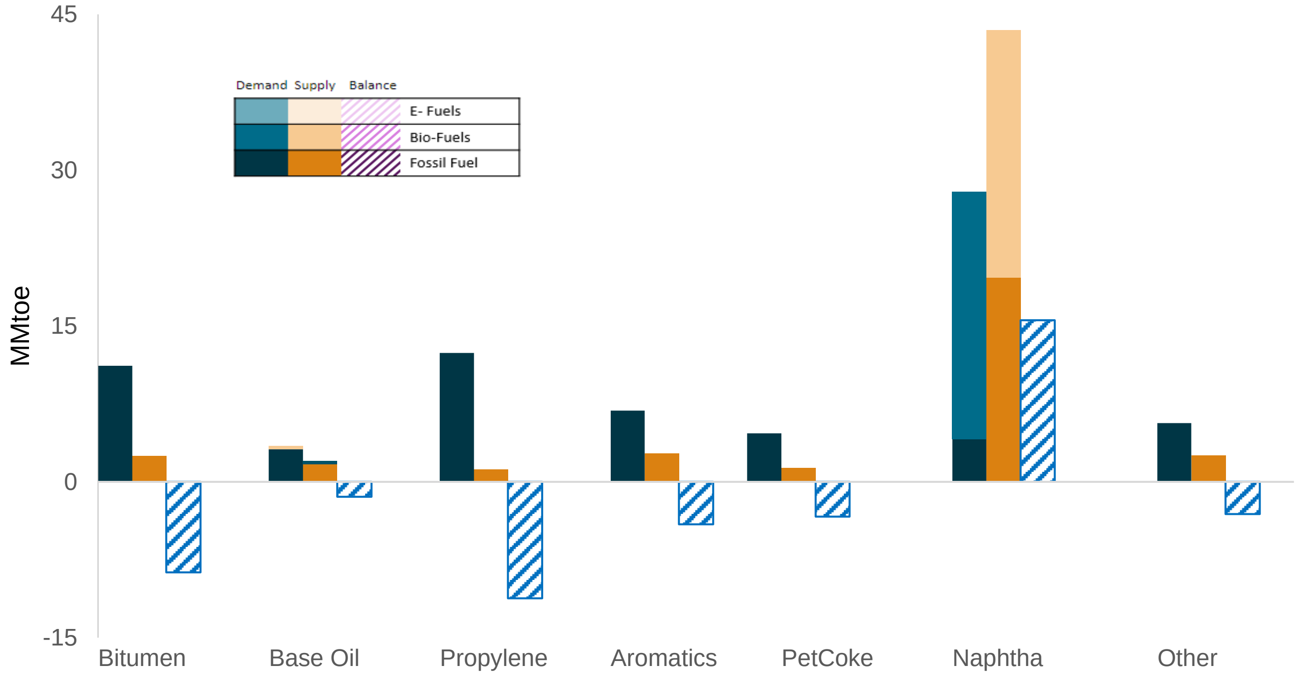
Figure 7.25 – 2050 EU+ fossil, bio and e- non-fuels balance, More Molecule (MMtoe)



Source: S&P Global Commodity Insights
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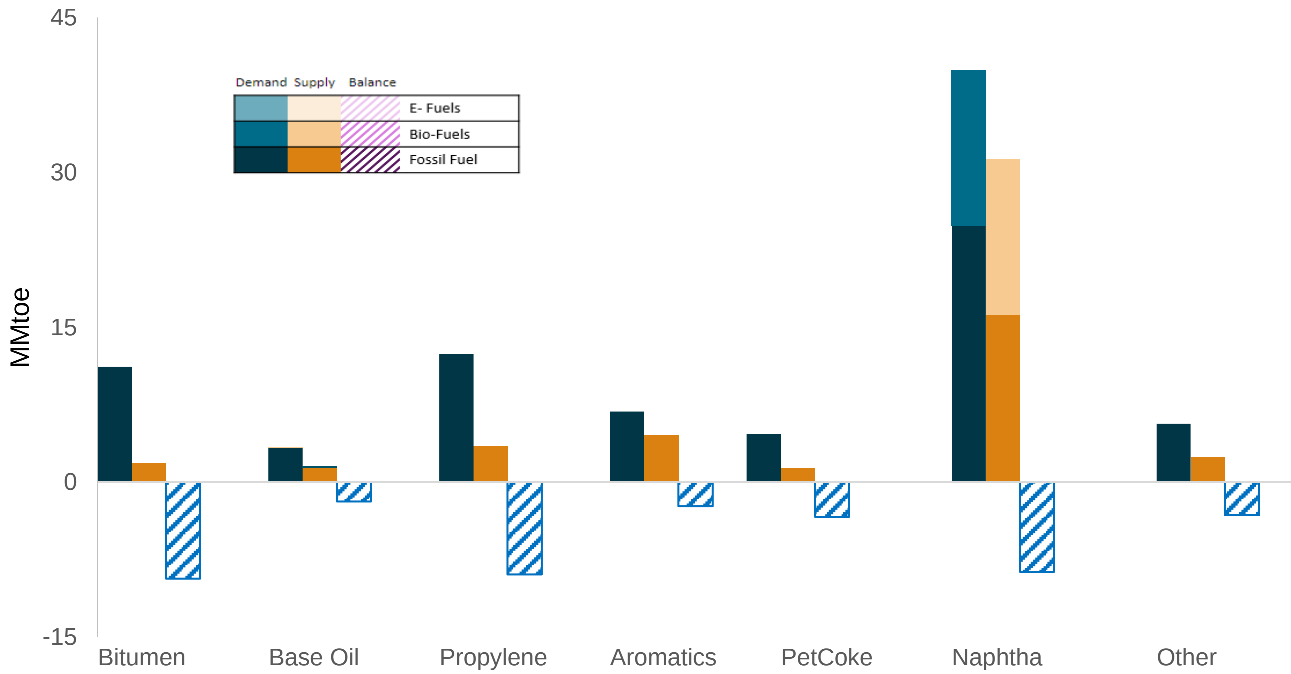
By 2050 the EU+ would be a net-importer of bitumen, base oils, petcoke and Other (C9 aromatics) to balance demand. The future dependence of the EU+ on bitumen imports, will require adaptation of logistical import facilities due to the specific nature of bitumen, with the need for hot transport for bitumen import.

By 2050, for these hydrocarbon products that are not used as fuels, and therefore do not contribute to direct CO2 emissions, there is far less substitution of fossil origin material with bio material compared to liquid fuels. In our models we have zero production of these non-fuel products from e-products. There is significant co-production of bio-naphtha from the production of bio-diesel and bio-jet, and a small volume of bio-base oils produced.

The deficit of propylene and aromatics could be reduced by additional production from the petrochemical industry – in Figures 7.22 to 7.25 above the balances for 2040 and 2050 do not adjust production of propylene and aromatics from the petrochemical industry although there is a surplus of naphtha in both scenarios.

In Figures 7.26 and 7.27 below, additional naphtha processing on petrochemical complex is allowed to reduce the propylene and aromatics import requirements back down to 2024 levels.

Figure 7.26 – 2050 EU+ fossil, bio and e- non-fuels balance, Max Electron with additional Petrochemical Production (MMtoe)



Source: S&P Global Commodity Insights
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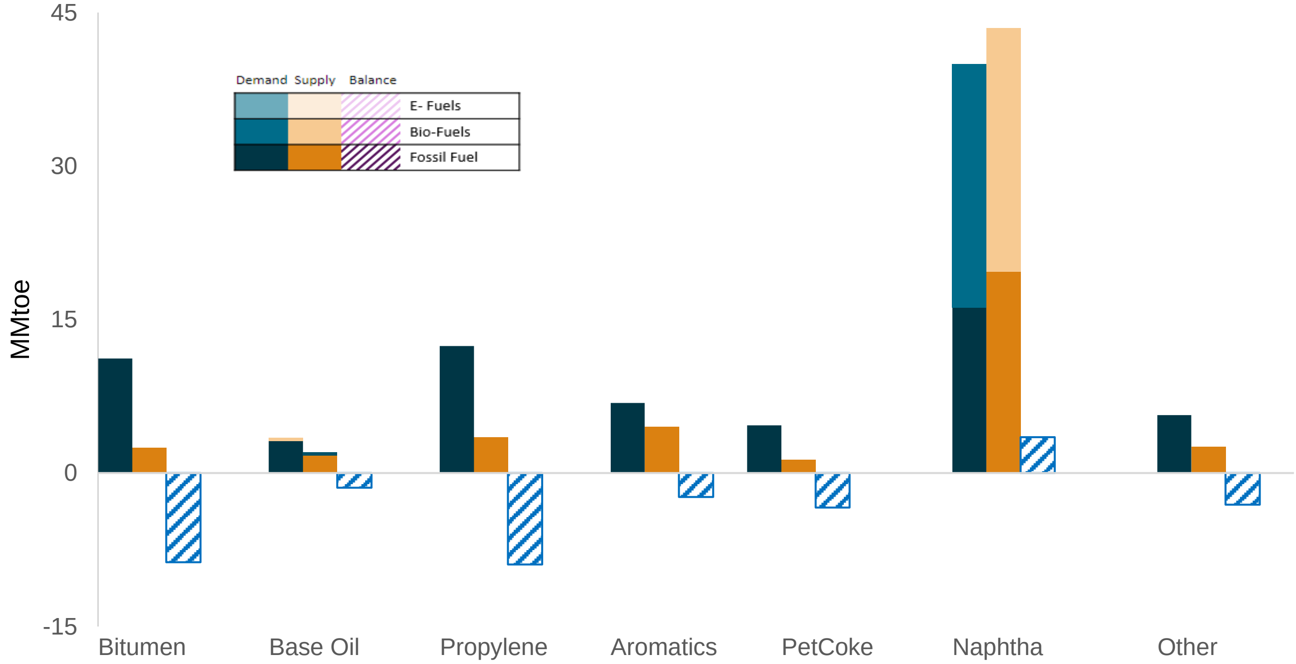
Figure 7.27 – 2050 EU+ fossil, bio and e- non-fuels balance, More Molecule with additional Petrochemical Production (MMtoe)



Source: S&P Global Commodity Insights
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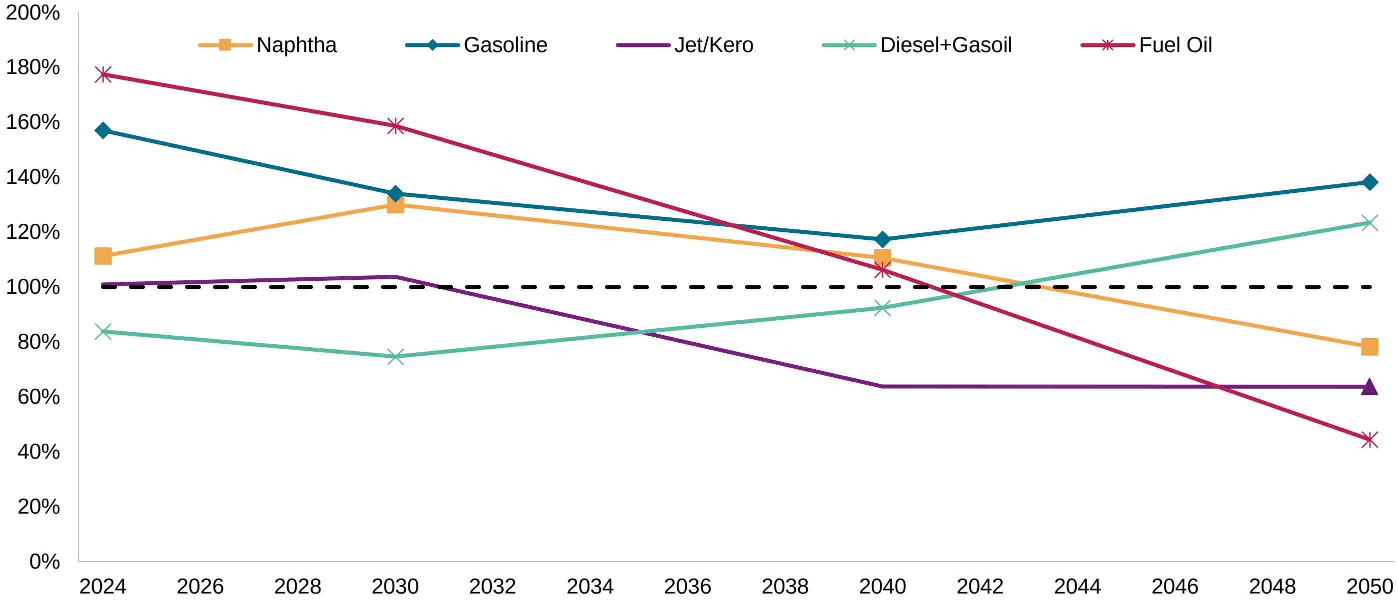
The additional petrochemical processing increases naphtha demand in 2050 by 12 million tonnes. Further increase in production from the petrochemical industry would likely require investment in additional capacity. In the Max Electron scenario by 2050 the EU+ has a deficit of naphtha, whereas in the More Molecule scenario the EU+ has a modest surplus, due to the additional bio-naphtha production in the More Molecule scenario. The More Molecule scenario is therefore better placed to support additional petrochemical industry production.

7.6 Total Liquid Fuel Supply Cover

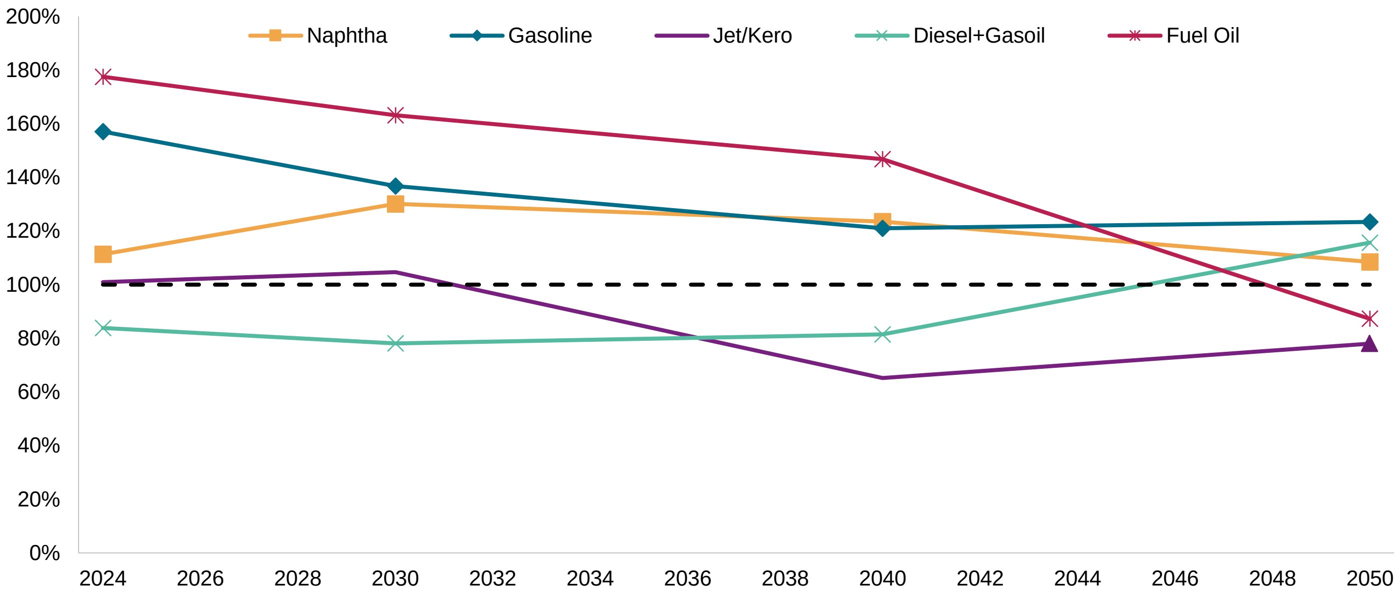
Combining all fuels demand and supply values allows us to calculate total fuel supply cover under the two scenarios out to 2050. This is shown in Figures 7.28 and 7.29 below.

Figure 7.28 – EU+ Max Electron Liquid Fuel Supply Cover



Source: S&P Global Commodity Insights.

Figure 7.29 – EU+ More Molecule Liquid Fuel Supply Cover



Source: S&P Global Commodity Insights.

In both scenarios, gasoline retains a supply cover above 100% out to 2050. Diesel supply cover improves as total diesel demand falls, and bio-diesel forms a greater proportion of the overall supply, resulting in supply cover above 100% by 2050. Fuel oil supply cover falls steadily as fossil refinery rationalization takes place. Jet/kerosene supply cover falls as e-jet volumes increase and with e-fuels imports being required as outlined in Section 7.3 above. In Max Electron, naphtha supply cover falls to 78% by 2050 as fossil production falls and bio-naphtha production volumes are not enough to maintain 100% supply. In More Molecule, naphtha supply cover remains above 100%, falling to 116% by 2050 – compared to Max Electron there is more supply of both bio-naphtha and fossil naphtha.

7.7 Distribution of Bio- and E- Fuel/Products Production 2024 to 2050

Projected EU+ biofuel processing capacity across the EU+ for both scenarios is shown in Figures 7.30 to 7.35.

Projected EU+ e-fuel processing capacity across the EU+ for both scenarios is shown in Figures 7.36 to 7.41.

In this analysis, countries have been grouped together into the below groupings to maintain anonymity of individual plant or country capacity.

Table 7.2: Bio- and E- fuels country groups 2030 and 2040

	2030 and 2040 country split
Region	**Countries**
A	United Kingdom, Ireland
B	Norway, Finland, Sweden, Denmark
C	Belgium, Netherlands, Luxembourg
D	Croatia, Italy, Portugal, Spain, Malta
E	France, Germany
F	Greece, Bulgaria, Romania, Cyprus
G	Austria, Switzerland, Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Latvia, Estonia

Table 7.3: Bio- and E- fuels country groups 2050

	2050 country split
Region	**Countries**
X	United Kingdom, Ireland, Norway, Finland, Sweden, Denmark, Belgium, Netherlands, Luxembourg
Y	Croatia, Italy, Portugal, Spain, Greece, Bulgaria, Romania, Cyprus, Malta
Z	France, Germany, Austria, Switzerland, Czech Republic, Slovenia, Slovakia, Poland, Lithuania, Hungary, Estonia, Latvia

Max Electron Scenario Biorefinery requirements in 2030

Group	2030 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**33.2**	**33.0**	**27.3**	**0**
A	3.8	1.6	3.3	**0**
B	4.0	3.9	1.2	**0**
C	2.5	7.1	2.5	**0**
D	7.4	8.8	6.5	**0**
E	9.1	7.2	8.9	**0**
F	1.7	1.0	1.3	**0**
G	4.8	3.5	3.7	**0**

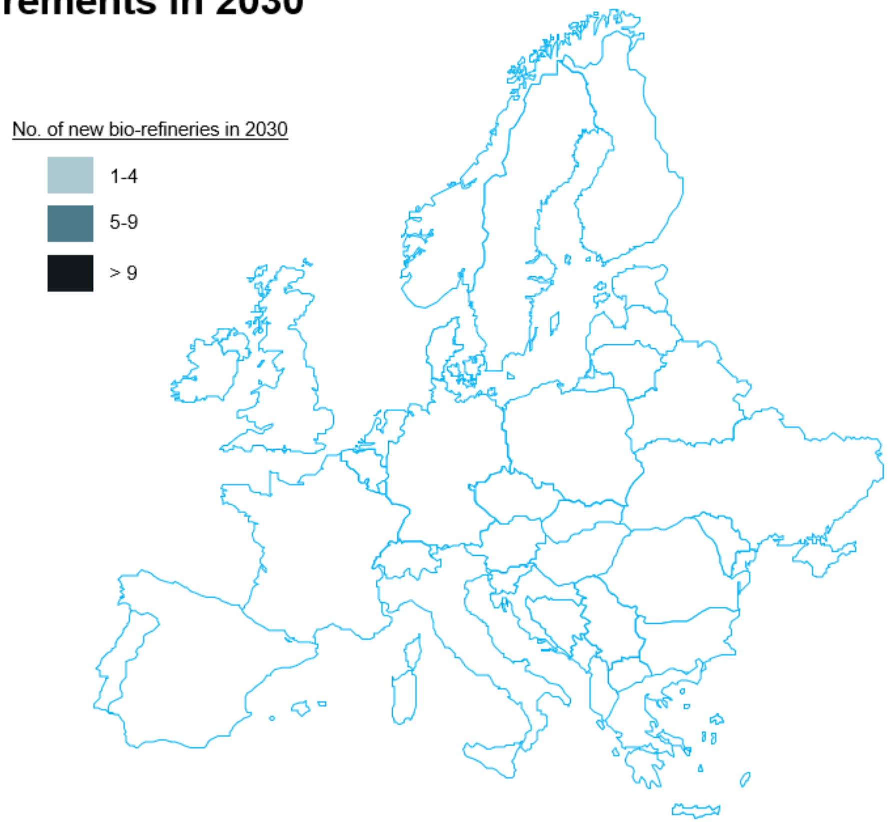


Figure 7.30 - Max Electron Biorefinery Requirement in 2030

More Molecule Scenario Biorefinery requirements in 2030

Group	2030 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**39.5**	**33.0**	**34.2**	**0**
A	4.3	1.6	3.7	**0**
B	4.9	3.9	2.7	**0**
C	3.3	7.1	3.3	**0**
D	9.1	8.8	8.7	**0**
E	10.4	7.2	10.1	**0**
F	2.0	1.0	1.5	**0**
G	5.6	3.5	4.2	**0**

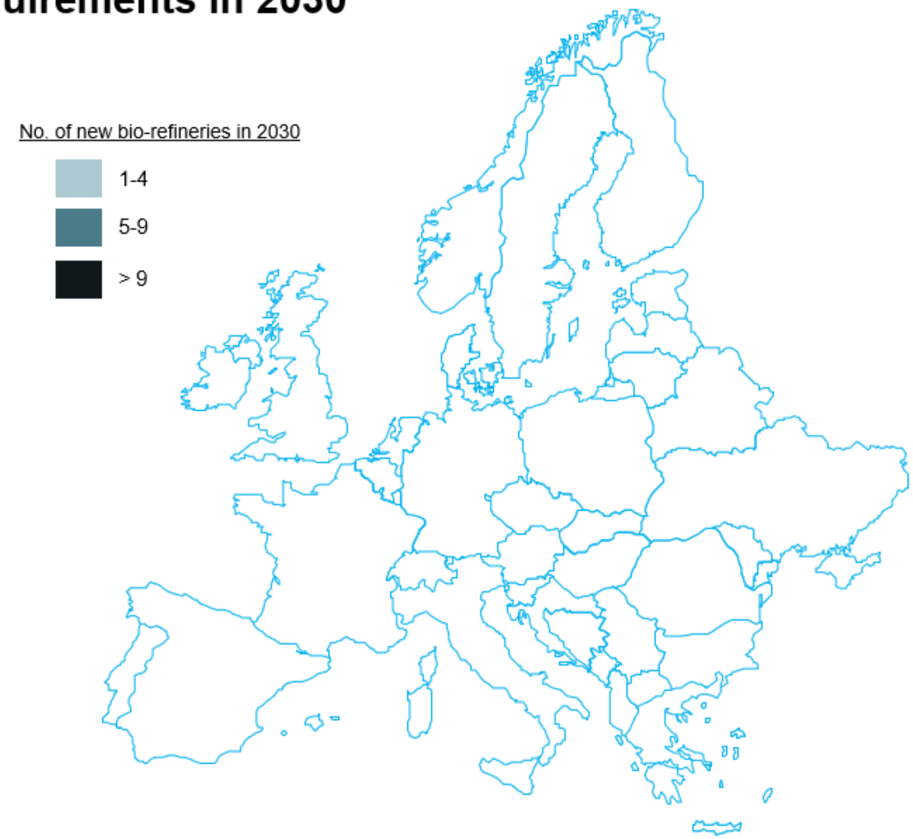


Figure 7.31 – More Molecule Biorefinery Requirement in 2030

Max Electron Scenario Biorefinery requirements in 2040

Group	2040 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**46.7**	**26.8**	**22.6**	**0**
A	6.6	1.2	5.9	**0**
B	3.9	3.6	1.1	**0**
C	2.9	6.3	1.7	**0**
D	12.6	7.0	6.5	**0**
E	10.4	5.3	4.2	**0**
F	3.2	0.7	1.8	**0**
G	7.1	2.7	1.4	**0**

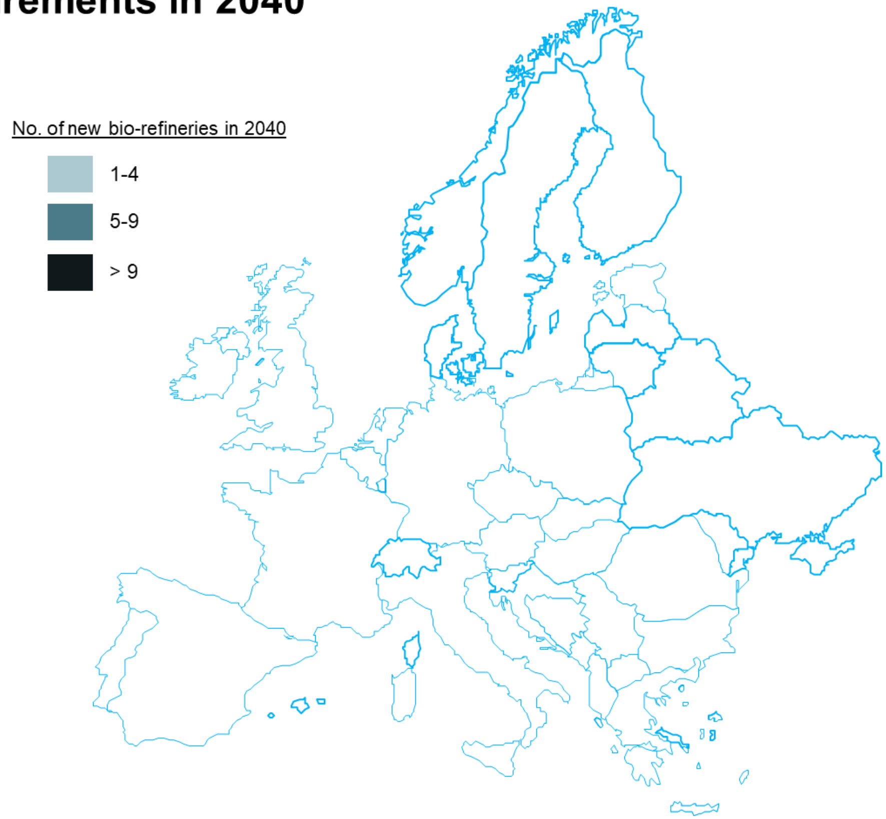


Figure 7.32 – Max Electron Biorefinery Requirement in 2040

More Molecule Scenario Biorefinery requirements in 2040

Group	2030 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**64.8**	**26.8**	**30.0**	**8**
A	8.6	1.2	7.7	**1**
B	6.0	3.6	1.5	**1**
C	4.6	6.3	2.6	**0**
D	17.7	7.0	9.5	**1**
E	13.6	5.3	4.9	**2**
F	4.5	0.7	1.9	**1**
G	9.8	2.7	2.0	**2**

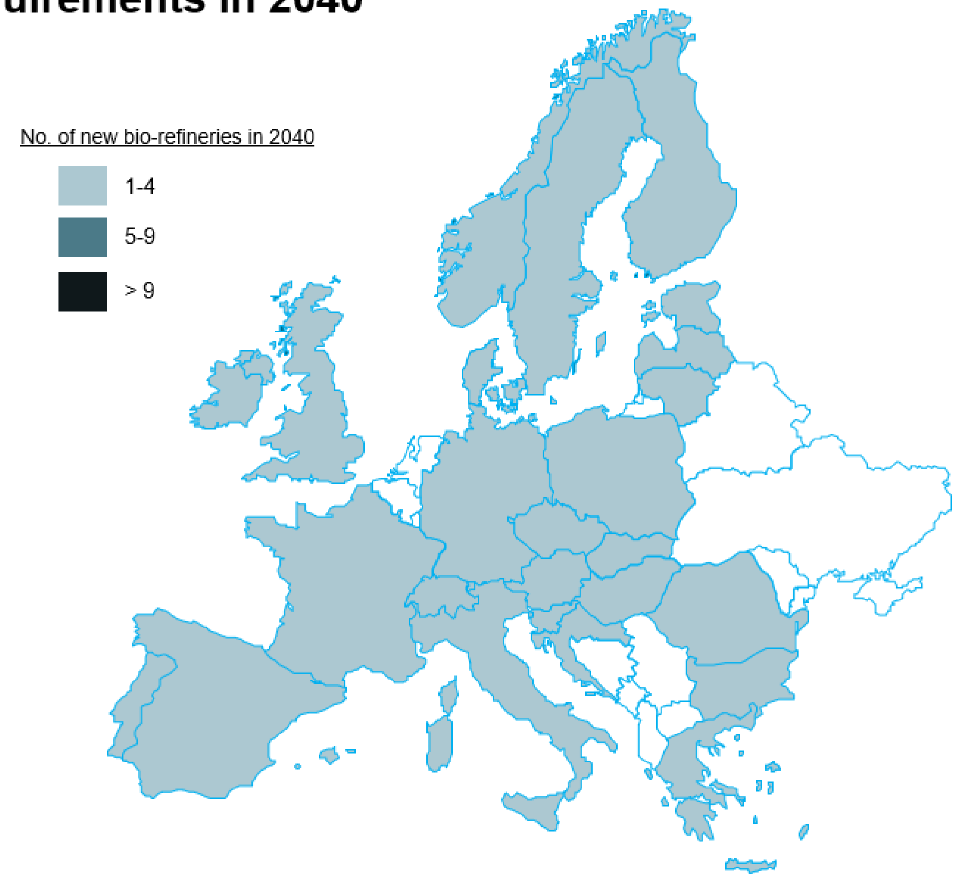


Figure 7.33 – More Molecule Biorefinery Requirement in 2040

Max Electron Scenario Biorefinery requirements in 2050

Group	2050 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**58.3**	**22.5**	**14.0**	**22**
X	15.4	10.1	8.4	**7**
Y	23.1	6.2	2.0	**5**
Z	19.8	6.1	3.6	**10**

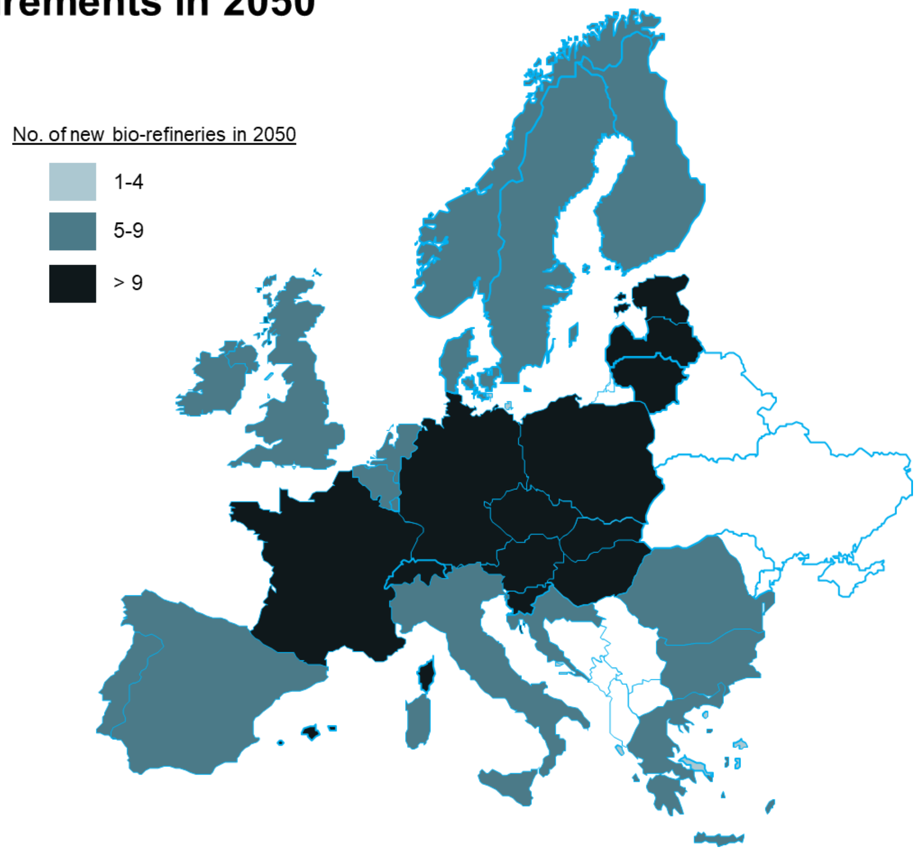


Figure 7.34 – Max Electron Biorefinery Requirement in 2050

More Molecule Scenario Biorefinery requirements in 2050

Group	2030 Total Biofuel demand (Mtoe)	Operational and firm capacity (Mtoe)	Available co-processing / unused HDT capacity (Mtoe)	New biorefineries required
Total	**90.0**	**22.5**	**19.6**	**48**
X	25.1	10.1	9.5	**15**
Y	35.2	6.2	3.7	**12**
Z	29.7	6.1	6.3	**21**

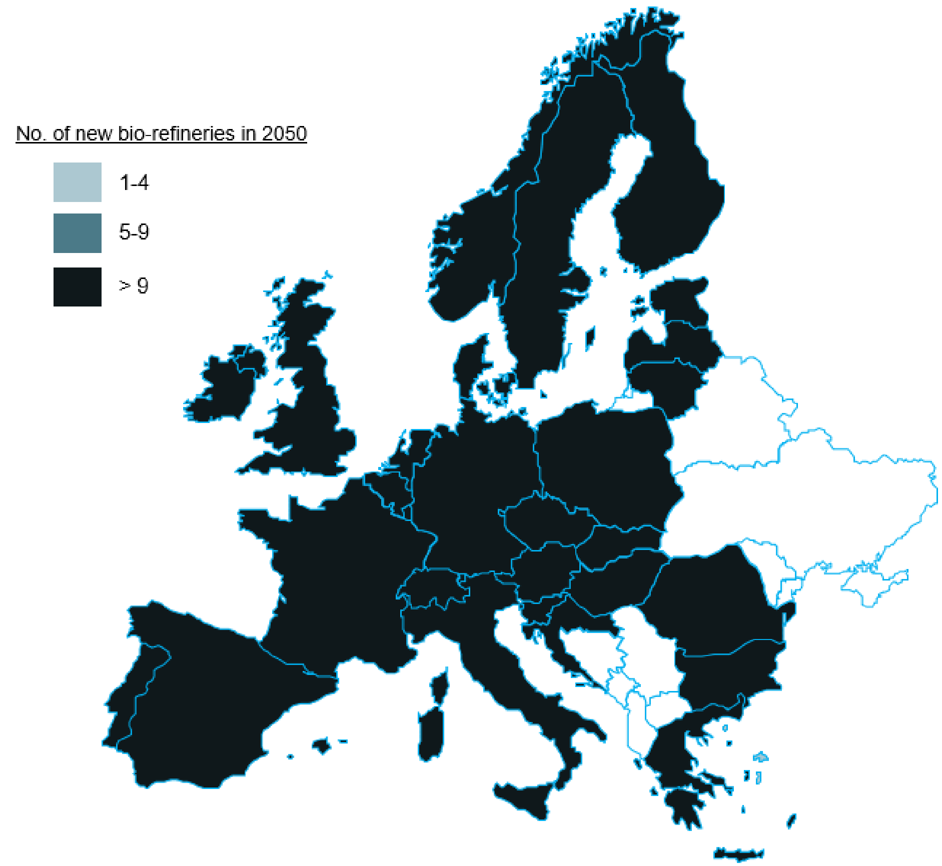


Figure 7.35 – More Molecule Biorefinery Requirement in 2050

Max Electron Scenario E-fuels requirements in 2030

Group	2030 Capacity (Mtoe)	No. of e-fuel plants required
Total	**0.3**	**1**
A	0	**0**
B	0.1	**1**
C	0.1	**0**
D	0.1	**0**
E	0.1	**0**
F	0	**0**
G	0	**0**

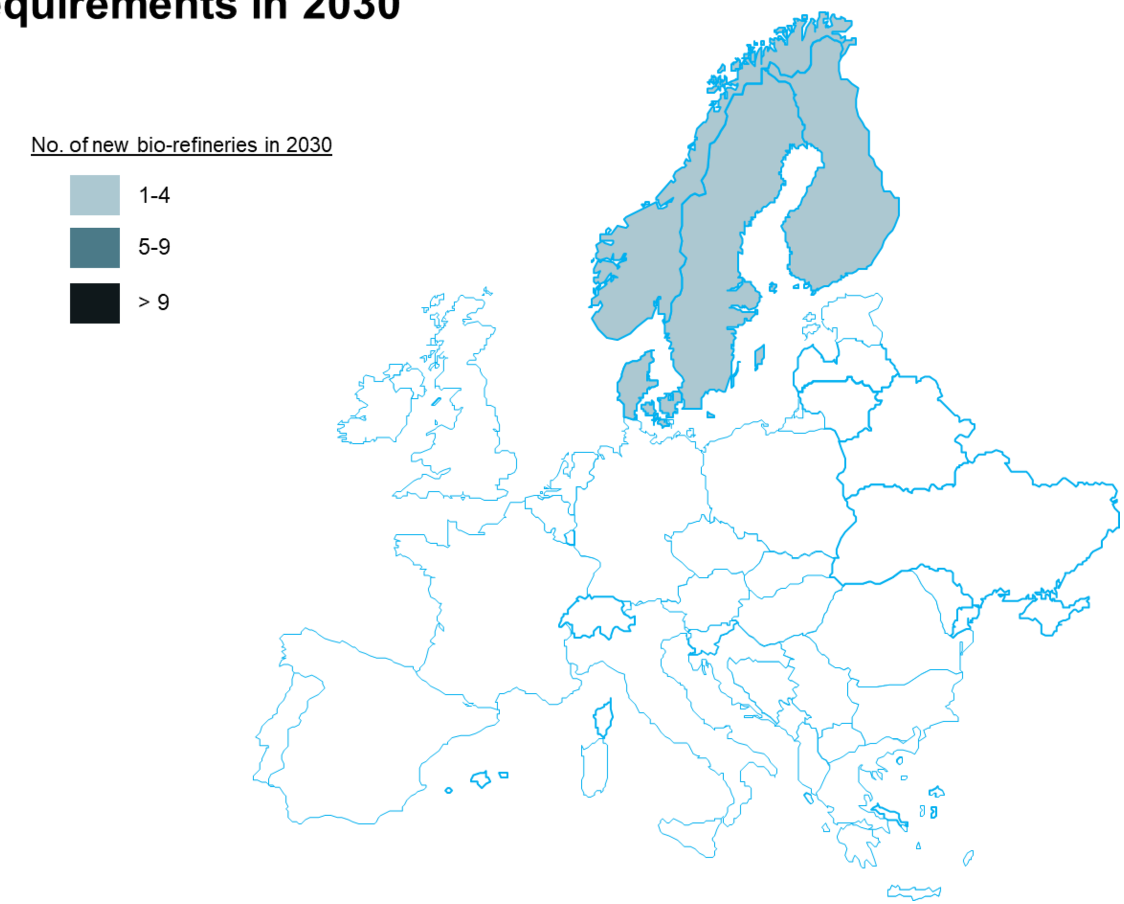


Figure 7.36 – Max Electron E-fuel Requirement in 2030

Max Electron Scenario E-fuels requirements in 2040

Group	2040 Capacity (Mtoe)	No. of e-fuel plants required
Total	**1.7**	**2**
A	0.2	**0**
B	0.4	**1**
C	0.3	**0**
D	0.3	**1**
E	0.3	**0**
F	0.1	**0**
G	0.1	**0**

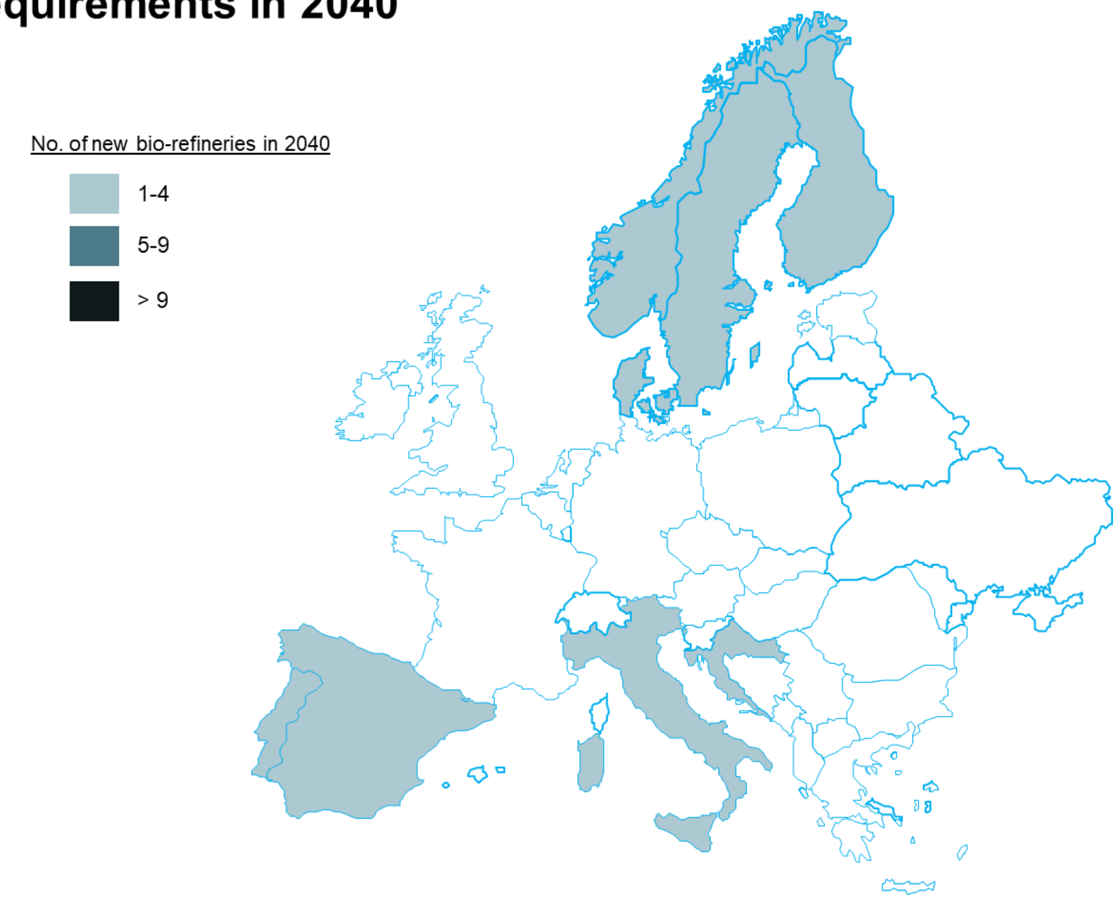


Figure 7.37 – Max Electron E-fuel Requirement in 2040

Max Electron Scenario E-fuels requirements in 2050

Group	2050 Capacity (Mtoe)	No. of e-fuel plants required
Total	**10.5**	**11**
X	6.2	**3**
Y	2.4	**7**
Z	1.9	**1**

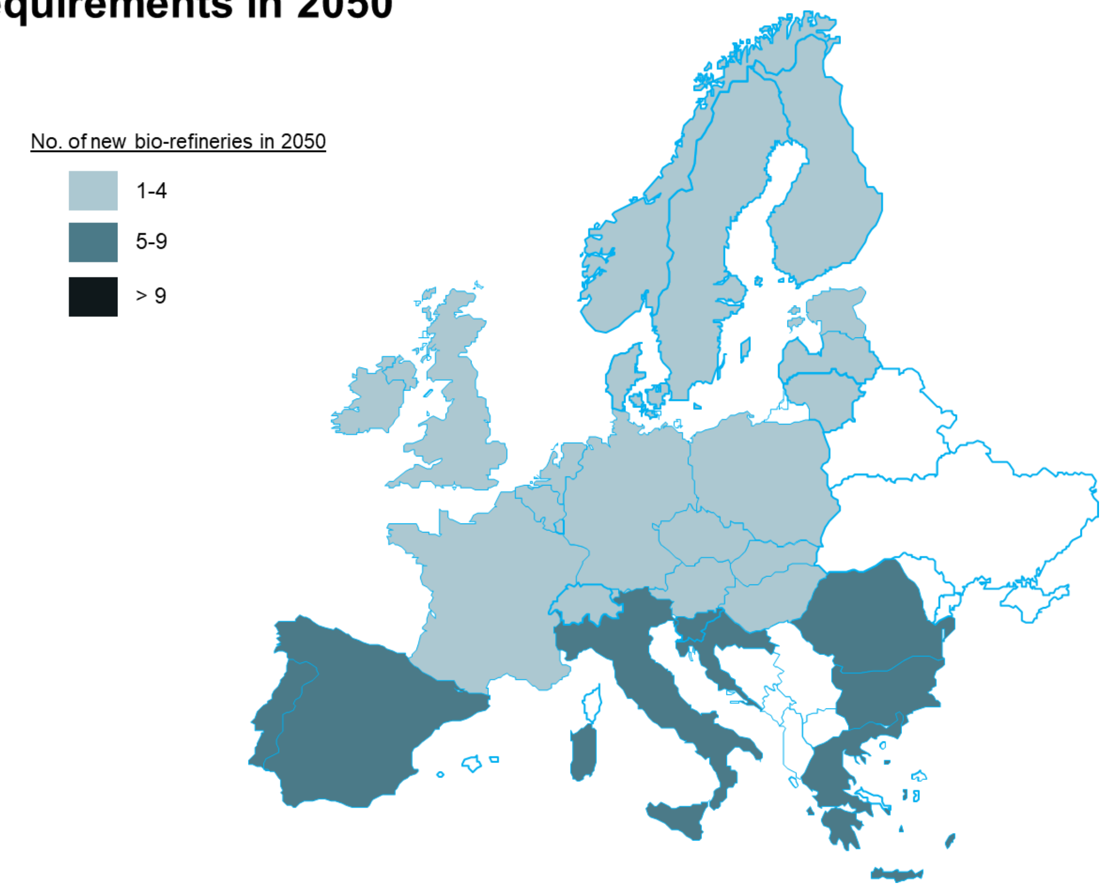


Figure 7.38 – Max Electron E-fuel Requirement in 2050

More Molecule Scenario E-fuels requirements in 2030

Group	2030 Capacity (Mtoe)	No. of e-fuel plants required
Total	**0.30**	**1**
A	0.04	**0**
B	0.07	**1**
C	0.05	**0**
D	0.06	**0**
E	0.07	**0**
F	0.00	**0**
G	0.01	**0**

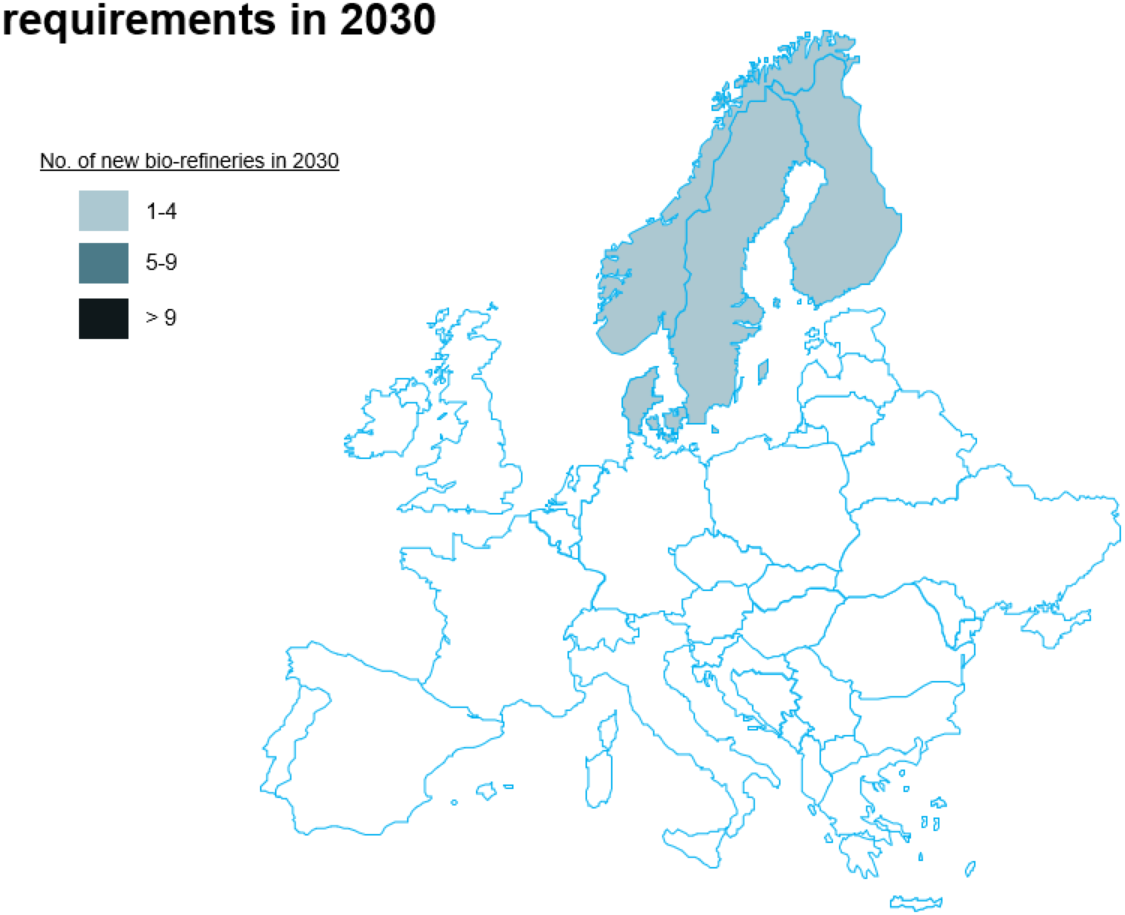


Figure 7.39 – More Molecule E-fuel Requirement in 2030

More Molecule Scenario E-fuels requirements in 2040

Group	2040 Capacity (Mtoe)	No. of e-fuel plants required
Total	**2.23**	**4**
A	0.31	**1**
B	0.52	**1**
C	0.37	**0**
D	0.43	**2**
E	0.42	**0**
F	0.07	**0**
G	0.11	**0**

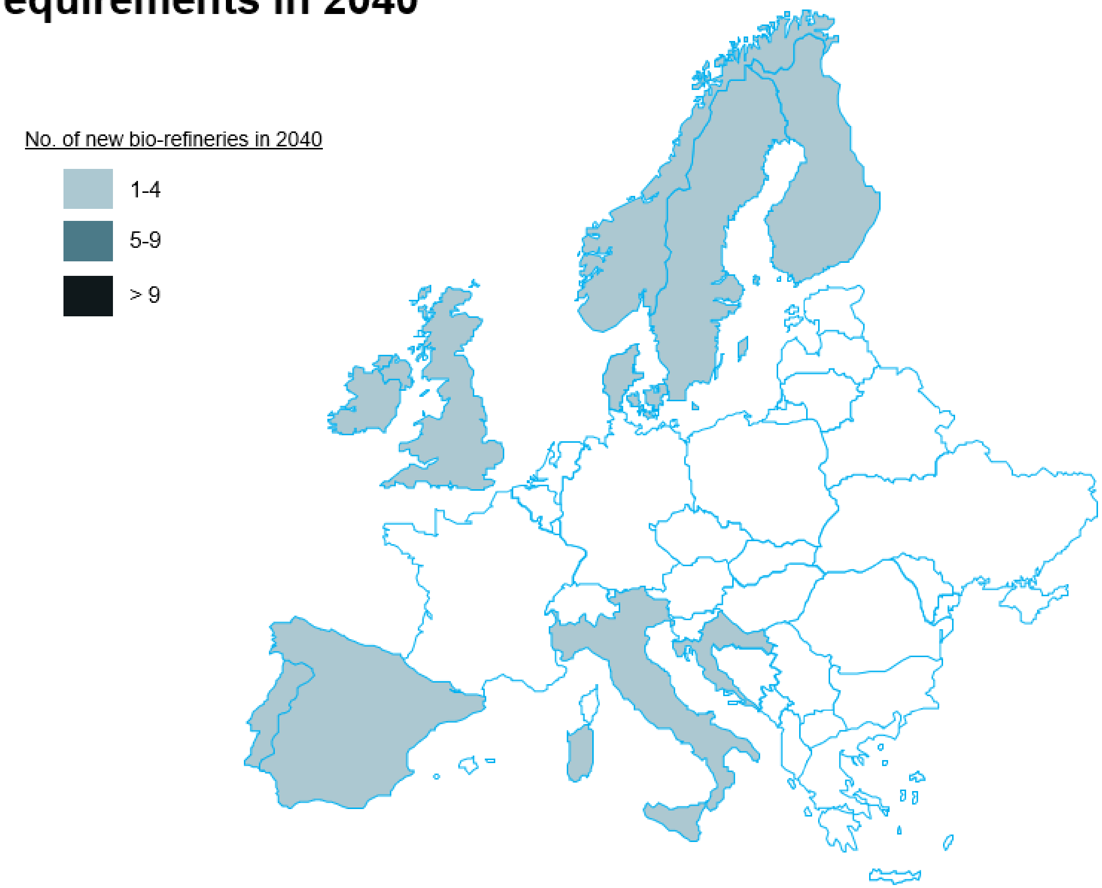


Figure 7.40 – More Molecule E-fuel Requirement in 2040

More Molecule Scenario E-fuels requirements in 2050

Group	2050 Capacity (Mtoe)	No. of e-fuel plants required
Total	**16.73**	**17**
X	9.87	**5**
Y	3.85	**8**
Z	3.01	**4**

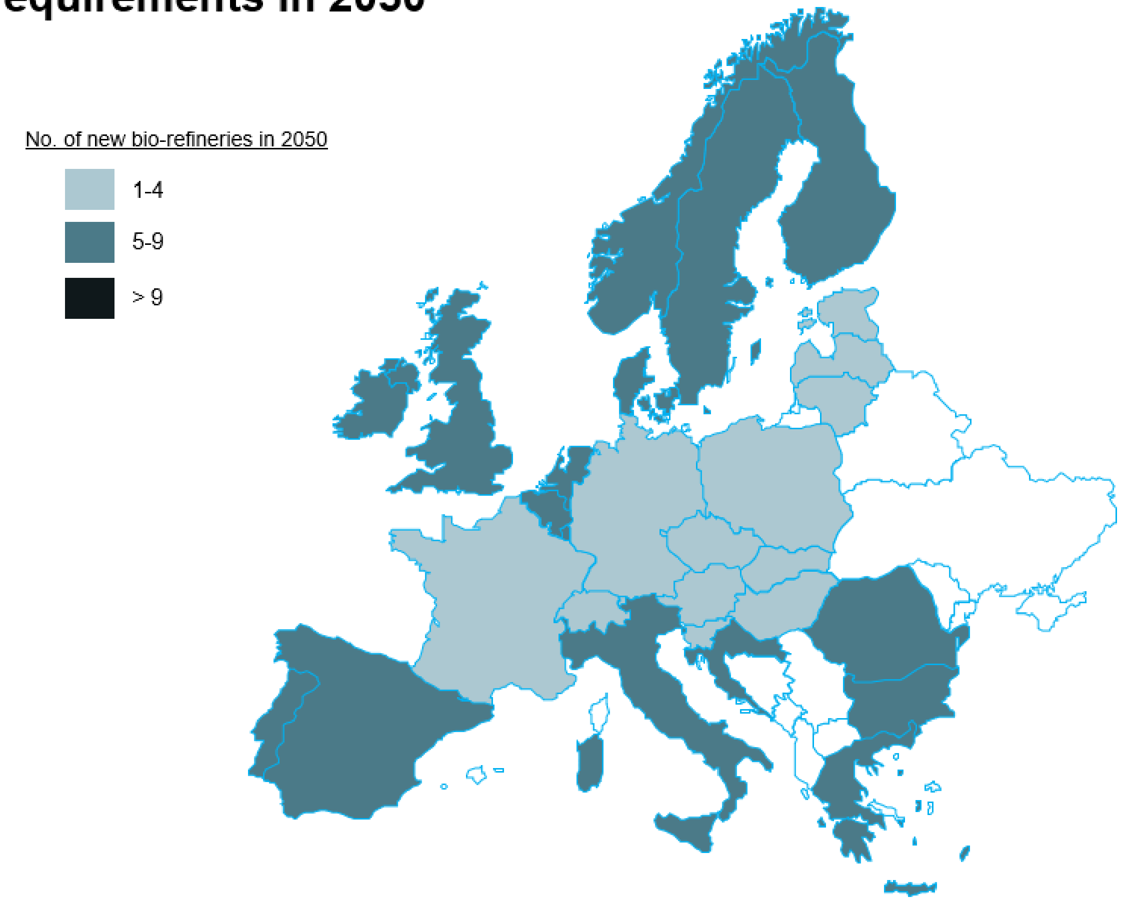


Figure 7.41 – More Molecule E-fuel Requirement in 2050

7.8 Specialty Products Security of Supply

In most cases specialty products do not contribute to CO_2 emissions, as their primary use is not as a fuel. Therefore, specialty product demand is far less influenced by the drive to net-zero emissions. However, the supply is influenced by fossil refinery rationalization.

Bitumen

In our LP modelling, bitumen price has been set at an import parity with supply coming from the Middle East. Even with this import parity price, conventional refining and stand-alone bitumen refineries rationalize over time, resulting in an increase in bitumen imports. In our scenarios, 2024 bitumen imports to the EU+ are 5 million toe. By 2050 this increases to 9.4 million toe in Max Electron, and 8.7 million toe in More Molecule. The biofuel and e-fuel plants do not make any bitumen and so cannot contribute to supply.

This future dependence of the EU+ on bitumen imports, will require adaptation of logistical import facilities due to the specific nature of bitumen, with the need for hot transport and heated off-loading facilities.

Base Oils

It is technically possible to make base oils and waxes via Fischer Tropsch process and so these can/could also be made from bio material or renewable power. However, the primary use of base oils is for production of lubricants and not for use as fuels and therefore base oils do not directly contribute to CO_2 emissions. In our analysis we have routed all production of “bio” and “e” molecules to the production of bio-fuels or e-fuels, in order to minimize CO_2 emissions. A small volume of bio-base oil is produced in 2040 and 2050 from the new biofuel plant bio-hydrocracker bottoms residue, but in all cases, this is not enough to meet demand and so the EU+ is expected to remain a net importer of Group II and Group III base oils.

As the fossil refining capacity is rationalized, base oil production capacity is also rationalized as refineries that have base oil plants close. Much of European base oil production capacity is Group I base oil plant, which would be expected to close due to changes in quality requirements in the base oil market. This would be expected to happen irrespective of any drive to net zero emissions. Net base oil imports are therefore expected to increase.

Propylene

Rationalisation of conventional refining reduces the production of propylene. In our scenarios propylene demand falls modestly from 14.7 million toe in 2024 to 12.4 million toe (a far smaller relative reduction compared to main fuels). The refinery rationalization increases the requirement of supply from imports or petrochemical plant production (e.g. naphtha crackers) from 8.9 million toe in 2024 to 11.2 million toe in 2050.

Additional processing of 12 million tonnes of naphtha in naphtha crackers could reduce the propylene deficit back to 8.9 million toe.

Aromatics (Benzene, Toluene, Xylenes)

Rationalisation of conventional refining reduces the production of aromatics. In our scenarios aromatics demand falls from 10.6 million toe in 2024 to 6.8 million toe by 2050. The refinery rationalization increases the requirement of supply from imports and petrochemical plant production (e.g. from naphtha crackers) from 2.3 million toe in 2024 to 4.1 million toe in 2050.

Additional processing of 12 million tonnes of naphtha in naphtha crackers could reduce the aromatics deficit back to 2.3 million toe.

Impact on Naphtha Demand

In both scenarios, the additional production of Propylene and Aromatics results in an increase in naphtha demand of 12 million toe. In the Max Electron scenario, this results in a naphtha import requirement of 8.7 million toe, whereas in the More Molecule scenario a modest naphtha surplus of 3.5 million toe remains.

Appendix A: Methodology, Assumptions and Description of Scenarios

Scenario basis and assumptions

As described in Section 4, S&P Global has a dedicated scenario modelling team, providing alternative future scenarios for clients via our Energy and Climate Scenario service. These are typically used by clients for creating and testing strategy. S&P Global has five different pathways out to 2050, illustrating the pace of change in long-term global energy supply, demand, and trade, based on current views and assumptions about economic growth, markets, policy, consumer behavior, and technology.

For this study, it was required to have more than one alternative scenario that achieved net zero GHG emissions for Europe by 2050. S&P Global has a scenario called **Green Rules** which is a faster energy transition than our base case. Green Rules is not net zero globally by 2050 but it is almost net zero for Europe.

S&P Global has separate commodity price sets for each scenario, which have been developed through modelling to provide the necessary stimulus for the required changes to happen, while also providing sufficient economic support to the industries which need to remain in order to supply the world's energy needs.

Therefore, it was decided to use this as the starting point for this study's scenarios. Green Rules was suggested to create two alternative pathways to net zero for Europe, these were called **Max Electron** and **More Molecule**. Max Electron achieving net zero by increased electrification and More Molecule via increased use of clean fuels.

In this section we describe the assumptions and basis of Green Rules.

In Green Rules, very strong public and political response to successive global crises drives governments to pursue — and successfully implement— long-term policies and strategies that directly link national security interests with decarbonization, which complements and bolsters ongoing climate ambitions and goals. Over time, these forces advance robust private investment and innovation that, combined with strong shifts in consumer preferences and behavior, lead to revolutionary changes in energy use and supply and move the world much closer to the Paris Agreement's climate change targets than in the Inflections (planning case) outlook.

Key elements of the Green Rules

1. Response to crisis drives reinvention and revolutionary change. Leaders and governments around the world are compelled by national self-interest and growing pressure from their societies (particularly younger citizens, voters and consumers) to reestablish global stability and pursue positive change in fundamental economic, social and security challenges — including climate change. This is especially driven by reactions to intense geopolitical conflict between major powers during the 2020s and the ongoing rise in extreme weather and carbon emissions.

2. Geopolitical rivalries play out in intense competition for world markets, prosperity and influence rather than via direct geopolitical or military conflict. Although geopolitical tensions and dissonance remain

strong, major players strive to prevent future conflict and global instability that they believe threatens their long-term economic and strategic interests.

3. National priorities are increasingly linked to economic independence, energy security and decarbonization. Geopolitically-driven energy crises highlight strategic vulnerabilities in dependence on fossil fuels, pushing most major countries to transition to lower-carbon energy as fast and as much as possible. These efforts coincide with governments' interest in rejuvenating national economies so they can compete in a global economy driven by future technologies — including a central role for clean energy technologies — making all of these pursuits national security priorities.

4. Clean energy technology development and access to critical minerals and new commercial markets become central elements of geopolitical rivalries. Major countries and companies will compete for access and influence in fast-developing market countries that will be new sources of strategic materials and low-cost manufacturing as well as future consumer markets.

5. Sustained and effective implementation of government policies and mandates provides powerful incentives for significant private investment in clean energy. The combined forces of successful government and private initiatives in decarbonization and clean energy drive a strong, sustained expansion of global investment and technology transfer that rapidly transform the energy systems of many leading countries and set the stage for more sustainable economic development in emerging-market countries around the world.

6. The transition to lower greenhouse gas emissions, plus fundamental changes in the global energy landscape, come at a significant economic and human cost. People, companies, infrastructure and whole industries are made redundant, with substantial investments required to replace the old and grow the new.

7. Global GHG emissions peak in 2023 and decline steadily through 2050, but global net-zero targets are not met. Although several major economies, including Europe, are able to reach or very nearly reach their 2050 GHG targets, political and practical constraints prevent most countries from meeting their climate and net-zero goals.

Key assumptions and changes in Green Rules

In Green Rules, acceleration of global decarbonization is delayed during the first several years by political and economic challenges. However, ongoing market momentum, combined with lessons learned by governments, companies and consumers and strong advances in effective implementation of existing policies and programs, helps clean energy technologies continue penetrating markets and displacing fossil energy. This leads to demand peaks for all three major fossil fuels by the end of the 2020s (oil: 2024; gas: 2030; coal: 2023. Revolutionary change in energy is poised to occur by the early 2030s as momentum intensifies across the energy, political and economic landscape, setting the stage for much more robust downtrends for fossil fuels and emissions in the years to come.

By the late 2030s, there is a marked acceleration in the rate at which the global energy mix and GHG emissions paths change as policies, regulations, technology trends and market shifts put into play in the previous two decades alter the energy landscape more expansively. Some economic turbulence remains as decarbonization policies and the broader costs of the energy transition continue to be borne across many sectors.

However, the economic intensity of these pains begins to level out as the transition ends and a new decarbonized global energy economy becomes mainstream. In the 2040s, ongoing market trends and changes in social and consumer behavior continue to shift global energy use and supply, with fossil fuels (oil, gas and coal) accounting for just over 40% of total primary energy by 2050, compared with 80% in 2023. Most cars on the roads of major cities in 2050 are propelled by electric motors rather than ICEs, and almost 80% of new car sales are some form of EV. In pipelines crossing many countries, hydrogen now flows rather than natural gas or oil — and almost 60% of global hydrogen supply is “green,” produced using water electrolysis powered by zero-emissions power sources, mainly renewables. More than 30% of global supplies are “blue” hydrogen, produced using reformed natural gas or coal and carbon capture and storage (CCS). In large tanker vessels crossing the seas, hydrogen-based fuels like ammonia, rather than crude oil, are often being transported. Also, in some parts of the world, jetliners are propelled by sustainable aviation fuels like biojet rather than oil-based jet/kerosene.

There are many more renewable energy installations and far fewer coal-fired power plants (with those that remain likely equipped with carbon capture technology) — with almost no coal capacity in OECD countries. Gas remains relevant in all markets, but demand is declining as its role as a bridge fuel diminishes and gas is pushed further from most end-use sectors. Offshore wind farms are common sights off the coasts of many countries. Many industrial facilities operate using electricity, natural gas, biogas or hydrogen rather than coal- or oil-based fuels. The world’s major cities abound with different forms of transportation that accommodate local weather conditions, energy resources and consumer preferences — but across most of them, tailpipe emissions (if there even are tailpipes) are more likely to be water droplets from delivery vans and trucks using hydrogen fuel cells rather than a mix of CO2, carbon monoxide and nitrogen oxide.

- **Primary Energy:** From 2023 to 2035, global energy demand rises almost imperceptibly at an average annual rate of just 0.08% per year, peaking in 2027 at 15.6 billion metric tons of oil equivalent. The global energy mix in 2035 has shifted markedly from that of 2023, with fossil fuels dropping from 80% to 64% of total primary energy use, and zero emission energy sources (hydro, nuclear and renewables) rising to 24% from 11%. The share of modern biomass (liquid biofuels, biogas, forest/agricultural waste) grows to 8% and traditional biomass (wood, charcoal, etc.) falls slightly, to less than 4%.

- **Oil:** Global oil (liquids) demand peaks in 2024–25. Demand in OECD countries never again reaches pre-pandemic levels, and China’s demand peaks in 2026. Indian oil demand continues to rise through the rest of the decade, but not enough to offset falling demand in the advanced markets or other developing countries. Total oil demand in non-OECD markets, excluding China and India, peaks in 2029. Through the early 2030s, steadily intensifying policies, rapidly changing consumer behavior and market penetration of EVs and other alternative vehicles reach an important turning point, and downward momentum in global oil demand builds strongly.

  In 2035, global oil demand is 89.2 million b/d — almost 15% below the 2023 level. Over the short term, a mix of geopolitical crises disrupts global oil and markets, causing heightened anxiety over supplies and once again driving average global prices above $100 per barrel. This latest crisis plays a strong role in accelerating demand destruction in the years that follow, bringing prices down sharply. During this period, oil producers continue to develop new supplies to offset production declines and meet ongoing fuel and feedstock needs, but as demand falls even more strongly in the early to mid-2030s, new investment falls, leading to tighter supplies for remaining consumers and a period of rebounding prices later in the scenario.

Global oil (liquids) demand in 2050 is about 60 million b/d — a level not seen in more than 60 years. This is more than 40% below oil demand in 2023 and about 6% below oil demand in 1990. The extended electrification of transportation across key markets, high fuel and carbon taxes on refined products, bans on oil-powered cars and trucks, extensive but varied approaches to public transportation, a step change in shared mobility via the car, and the establishment of a significant circular economy for plastics are all key factors that shrink oil consumption. In 2050, oil still accounts for almost 60% of global transportation energy use — most of which is by HMDVs and jet airplanes — but this is down from 94% in 2023. Oil falls to 16% of global primary energy, down from 31% in 2023.

On the supply side, it takes some time for major suppliers to become more attuned to the new energy landscape of declining oil demand across most major markets. This leads to increasingly intense competition for the remainder of the market. By the early 2040s, OPEC crude supply surpasses non-OPEC, and ongoing global oil production is increasingly dominated by the world's lowest-cost producers — mainly in the Middle East.

- **Gas**: Global demand for natural gas peaks in 2030, owing to a mix of energy security concerns and rapidly expanding market penetration of battery-backed renewable capacity in large key markets, which slows new build of gas-fired power plants and reduces the utilization rates of existing plants. Gas demand falls steadily in most large economies through the rest of the 2020s, but it rises in some key developing countries that turn to gas as the "bridge fuel" to either preclude new use of coal or displace existing uses, particularly in power.

  This rise in gas demand in developing countries comes at a time when new gas production and LNG liquefaction facilities (built to replace Russian gas flows to Europe) provide ample global gas supply, which strongly impacts prices by the late 2020s and early 2030s, when global demand begins a steady long-term decline as falling gas use in China and the OECD countries is partially offset by demand growth in some key emerging markets. From 2023–35, these factors keep global demand essentially flat through 2035, resulting in total demand of 142 Tcf — about 270 Bcf lower than in 2023, and major benchmark prices are a fraction of levels seen in 2023–24.

- **Coal:** After the brief rebound in global coal demand in the early 2020s, driven mainly by short-term incidents of market tightness, global demand never again surpasses the peak set in 2023, after which long-term market fundamentals and momentum resume coal's steady decline, which accelerates in the late 2020s and early 2030s as decarbonization trends accelerate and coal use in all sectors is displaced by a mix of clean energy technologies, natural gas and electricity. By 2035, global coal demand is 35% lower than in 2023, with falling Chinese coal use responsible for half of this decline.

Chinese coal use falls from almost 60% of total primary energy demand in 2023 less than 40%. The biggest fall is in the electric power and sectors. Coal-fired generation in China declines by more than 30% from 2023 levels, falling to about 25% of total power generation (down from more than 60% in 2023). Even as China's coal use falls rapidly, it remains the world's largest coal-consuming market, representing a growing share (61%) of global coal demand by 2035. But China's share is distorted by the rapid decline in coal use in all regions and across most countries — even India. Falling coal use in OECD countries makes up the second-largest share of coal's global demand destruction. Coal use also declines in India during this period (down by 130 MMt), but at a much slower rate as India continues to heavily rely on coal-fired power.

- **Electric power:** Global power demand grows at an average annual rate of 3.3% in 2023–35, nearly doubling global power use in this period. The fastest growth is driven by transportation (15% per year) and energy transformation (18% per year), including green hydrogen production. The greatest total demand growth by volume is in industry and residential and commercial heating. The fastest average annual demand growth is in non-OECD Asia, excluding China and India (4.6%) and Latin America (4.1%). Growth in China and India rises by 3.9% and 5.5%, respectively. Generation fleets see accelerating shifts in energy mix during this period despite uncertainties over politics, policy, material supplies and rising trade barriers. Greenfield power capacity in every region is dominated by battery-backed solar PV and wind, both onshore and offshore. A substantial number of existing coal and gas plants remain in operation in 2035 (3.9 TW — representing more than 20% of global capacity), but many operate at declining utilization rates since they are repurposed to back up rising renewable power capacity before being retired. New fossil plants are added in most markets, but most of these are gas-fired plants, with global net capacity additions (new plants minus retired plants) growing through the early 2030s.

  In contrast, global net additions of coal-fired power turn negative by 2026 as coal plant retirements accelerate in OECD countries and China — far outpacing new plants still being built in India and other parts of developing Asia. By 2035, global coal capacity is falling by an average of 60 GW per year, compared with an average annual increase of almost 20 GW in 2020–23. Natural gas capacity grows strongly through the early 2030s, with new plants built in most regions of the world. In developed markets and China, most new gas-fired build is added for grid reliability and energy security, with new plants operating at generally low utilization rates. By the late 2020s, retirements in OECD markets exceed new additions, leading to falling gas capacity and generation levels. In developing countries, most new gas power plants built in the 2020s and 2030s are for base load service to help power economic growth in these countries. Some new hydro is also added, mostly in developing Asia, with China and India dominating additions, but also in Africa and Latin America. New nuclear is added as well, also dominated by China and India. Some new nuclear capacity is added at existing sites in the United States and existing plant operations are extended, but not enough to prevent retirement of the country's oldest nuclear plants, which results in a net decline in nuclear power through 2035.

- **Renewables:** The combination of energy security concerns, cleantech and climate change actions by governments and corporations, as well as shifting behavior by consumers, intensifies what is already a powerful expansion of renewable energy development across all regions and sectors. This is enabled by massive and still growing Chinese manufacturing capacity, in addition to growing supplies from new producers in other parts of developing Asia and emerging markets adjacent to US and European markets — all of which drives down average global costs. Between 2023 and 2035, renewable primary energy and power renewable generation both grow at an average annual rate of approximately 13%, respectively reaching almost 2.2 billion metric tons of oil equivalent and 21 TWh — more than four times the levels of 2023. This compares with 11% average annual growth for renewable primary energy and power generation in the Inflections scenario, which sees energy and power generation levels of 1.7 billion metric tons of oil equivalent and 17 TWh, respectively. By 2035, renewables account for more than 55% of global power capacity and almost 50% of total generation. This compares to 29% of global capacity and 16% of total generation in 2023. This growth does not come without challenges during this period, ranging from rising trade barriers against cheap Chinese imports in the US, Europe and OECD Asia to strained supply chains for metals, materials and final equipment, which leads to periodic supply constraints across the renewables value chain and higher input costs. Contributing to this are permitting, dispatch and interconnection barriers in power markets that are actively evolving to accommodate this revolutionary change.

- **Batteries:** An increasing share of new renewable power capacity is supported by grid-scale battery installations, whose cell costs are largely driven down by electrification in the transportation sector. Between 2023 and 2035, installations of battery-based grid storage around the world increase by a factor of more than 9 to a total capacity of 840 GW (which is more than the entire current-generation capacity of OECD Asia). Throughout the 2020s, the rapid increase in demand for both EVs and renewable energy puts great strain on battery supplies and costs. This constrains growth in both these markets, but also leads to government and market responses similar to what takes place for renewables. Policies, regulations and market responses to supply, demand and price signals help to drive changes in permitting and development of battery manufacturing and to expand investments in new materials supply for existing batteries — as well as to stimulate innovation in alternative battery technologies based on different chemistries and base materials.

Green Rules conclusions

In the Green Rules scenario, the forces of decarbonization and energy security do not just supplement but surpass climate change mitigation as the primary driver of the energy transition. This serves to supercharge the pace and scope of the global energy transition. In this outlook, the world makes revolutionary progress toward climate change mitigation. It establishes a pathway where the rise in average global temperature through 2100 is kept below 2 degrees — without driving the global economy into a downward tailspin or forcing the existing global energy industry to immediately alter its businesses, operations and investments. It does pose hard choices with difficult outcomes for many countries, companies, workers and consumers. This pain is real and costly. For these reasons, some of the more extreme measures needed for many countries to reach net-zero GHG emissions by 2050 are not taken, and so, while some important markets reach their 2050 GHG goals, most countries do not.

The Green Rules scenario is built to reflect a long-term outlook where many expectations about society, politics, consumer behavior and advances in clean energy technology and policy are stretched to produce an alternative view of the future in which decarbonization and the energy transition move at a much faster pace than in the “base-case” Infections outlook. As a traditionally developed scenario, Green Rules is not designed to meet a particular target for global emissions or global temperature rise. Rather, it is meant to present a view of the world that could happen under a range of strong assumptions, even if many who assess it do not think that it will happen.

This makes Green Rules an important benchmark against which to compare other, more extreme outlooks for an accelerated energy transition — particularly cases designed to reach global net-zero GHG by 2050.

Road transport modelling methodology

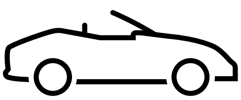
The road transport sector is broken down into three main groupings:

- Light Duty Vehicles – passenger cars and light commercial vehicles (<3.5 tonnes)
- Motorbikes
- Medium and Heavy-Duty vehicles – consisting of four sub-sectors:
  - Light-Medium Duty Vehicles (3.5-6.0 tonnes gross weight)
  - Medium Duty Vehicles (6.0-15.0 tonnes gross weight)
  - Heavy Duty Vehicles (>15.0 tonnes gross weight)
  - Utility Vehicles (buses, coaches, special vehicles such as refuse trucks, etc.)

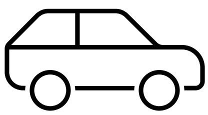
These are all modelled as time series stock models, with some additional econometric relationships. The road passenger model is a stock model based on the sales of new vehicles and the retirement of existing vehicles. The road freight models include econometric relationships between tonne-kilometers transported and industrial output.

Light Duty Vehicles Model

The LDV model consists of the passenger and light commercial vehicle segments –vehicles up to 3.5 tonnes (around 8,000 pounds).

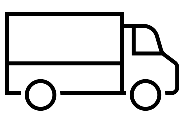


Class A-E
Small to large sedans

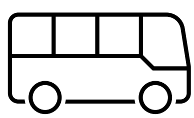


Multipurpose vehicles (MPVs)
station wagons and mini vans

Crossover utility vehicles(CUVs)
Sports utility vehicles(SUVs)



Pick-up trucks



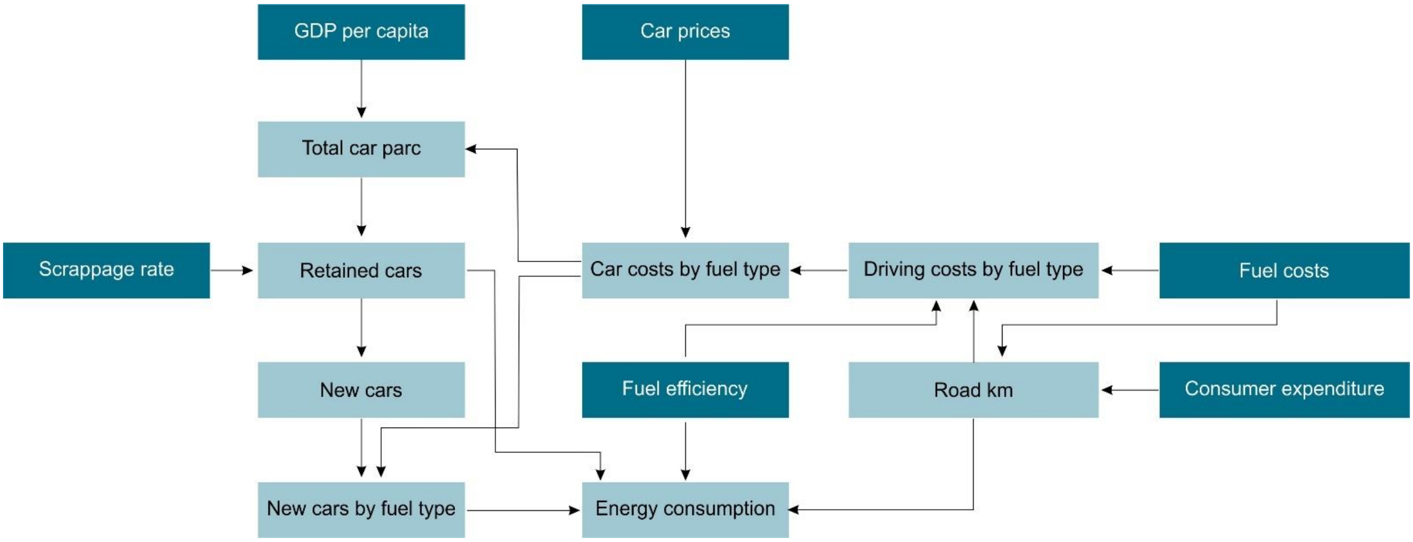
Other light commercial vehicles

The LDV forecast sales by eight vehicle propulsion technologies:

- Gasoline
- Diesel
- Full Hybrids: Gasoline, Diesel, Natural Gas (i.e. not plug-in)
- Plug-in Hybrid Electric Vehicles: Gasoline, Diesel, Natural Gas
- Pure Battery Electric Vehicles
- Natural Gas Vehicles

- LPG Vehicles
- Hydrogen Fuel Cell Vehicles

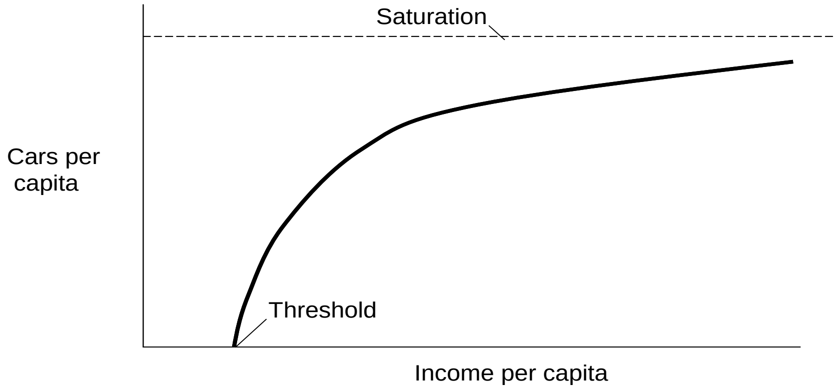
Each vehicle technology is modelled in terms of new registrations, scrappage and the total on-road fleet, (vehicle parc). The figure below shows how the passenger vehicle model is linked together. It is based on a stock model with the total car parc divided between new and retained cars and the various fuel types. The cars are then multiplied by the annual average distance driven and the average fuel efficiency for new and retained cars to determine the fuel consumption.



GDP per capita provides the income indicator driving the growth in the total car parc. New car sales/registrations are the difference between the total car parc and scrapped cars, with the scrappage rate an exogenous input. The type of new cars entering the market is a function of the relative economics of the different power trains as well as policy measures. Running costs are a function of the car cost (including any subsidies), insurance and other charges, fuel costs and fuel efficiency. Other policy restrictions are included, such as banning certain types of vehicles.

The fuel efficiency of new vehicles is an exogenous input, while the average distance driven (road km) is a function of the cost of fuel and individual wealth. Combining the parc data with the fuel efficiency and distance driven provides the overall fuel consumption by power train. This is broken down into the different fuel inputs required.

The demand for passenger cars can be described by a reciprocal model. There is a critical level or threshold level of income below which cars are not affordable. There is an upper boundary or satiety level beyond which demand will not grow (even millionaires do not generally own more than two or three cars at a time). The figure below illustrates the per capita demand for cars as a function of per capita income. The satiety level has been estimated using cross-country data but can be used as a policy variable to adjust the level of market saturation.



Changes in the cost of car ownership can shift the threshold and demand curve further along the disposable income per capita axis. Once the threshold level has been determined, then the reciprocal model calculates the overall car parc.

The equation works well for relatively high-income groups, where they approach the satiety level, i.e. in the section of the curve above where its differentiation is greatest; the point where the slope on the curve is changing the fastest as the income per capita increases. Below this level a form of logistic curve is the best fit. The car per capita equation is modified to take this into account.

Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km.

Annual cost of driving per new vehicle

The annual cost of driving a new vehicle will depend on fuel prices, kilometers travelled, efficiency of the new vehicle, plus any annual fees imposed as policy levers to encourage/discourage driving a specific type of vehicle. The annual driving costs are unitized by dividing by the average distance driven to give a cost per 1000 km. The total driving cost is the sum of the car cost, plus the annual fuel costs and the annual taxes.

Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fueling stations/points and conceptually how easy it is to maintain. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing gasoline and diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

Annual distance driven (road km)

The annual distance driven per vehicle can either be an internally calculated value based on the retail fuel price and GDP per capita or it can be an exogenous variable defined by the model user. An advantage to having this variable as an exogenous input is that it enables the user to test out the sensitivity of the fuel demand to this key input.

As we look into the future, at new policies that can be created to impact vehicle miles travelled (VMT), such as congestion charging, limit parking, and car sharing these factors will need to be incorporated.

The starting point for electric vehicles is less than for internal combustion vehicles. Electric vehicles are assumed to be able to drive assume 10,000 km per year (40 km per day for 5 days a week for 52 weeks in the year), and 20,000 km for LCV.

Energy consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

Inputs and Outputs

The key inputs to the model include:

- Real GDP per capita and average consumer expenditure
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated road tax and insurance
- The retirement profile of the existing fleet of cars
- Fuel efficiency of new vehicles
- Policy options to favour certain technologies and change the average road km driven

The key outputs are:

- Fleet of cars by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emissions

Motorbike Model

Motorbike ownership is linked to the urban population and to the per capita car ownership, as well as average income. It grows as the urban population grows and as average incomes increase. However, as average incomes continue to grow so there is a switch towards cars and as such motorbike sales plateau and then start to decline, with the motorbike fleet following this trend.

The choice of power trains for new motorbikes is split between gasoline and electric. The split is exogenously determined to enable the user to reflect policy measures.

Inputs and Outputs

The key inputs are:

- GDP per capita and consumer expenditure
- Urbanisation
- Cost of motorbikes
- Interest rates
- Fuel efficiency of new motorbikes
- Policies to promote/discourage motorbikes and different fuel-types; mainly gasoline or electric
- Policies impacting distances driven

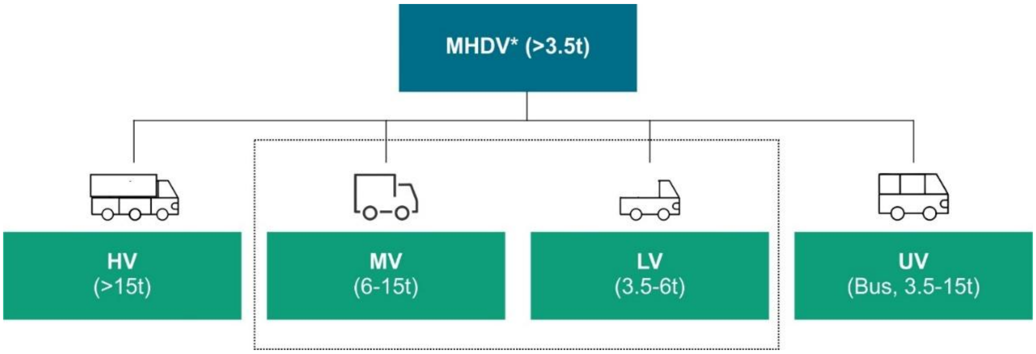
The outputs are:

- Motorbike parc, sales and retirements
- Distance ridden
- Fuel consumption
- Annual running cost
- Carbon dioxide emissions

Medium and Heavy Duty Vehicle Model

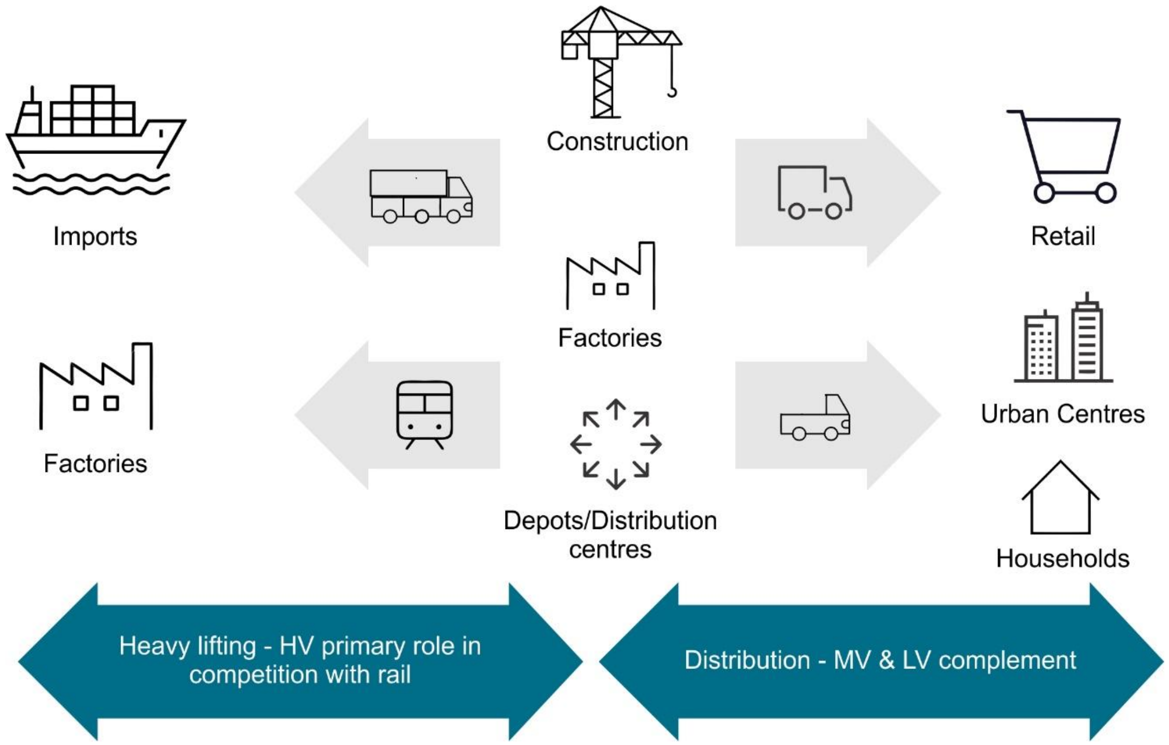
This consists of four sub-sectors:

- Light-Medium Duty Vehicles – LV (3.5-6.0 tonnes gross weight)
- Medium Duty Vehicles – MV (6.0-15.0 tonnes gross weight)
- Heavy Duty Vehicles – HV (>15.0 tonnes gross weight)
- Utility Vehicles – UV (buses, coaches, special vehicles such as refuge trucks, etc.)



The light, medium and heavy-duty vehicles are all moving freight, while the utility vehicles move people and refuse. Conceptually, the heavy-duty vehicles are involved in the heavy lifting, transporting large volumes of freight, while the medium and light-medium are primarily involved in freight distribution within urban areas, to retail outlets and households. Utility vehicles tend to be focused on moving people around urban area.

Conceptual view of MHDV modes



Within each sub-sector is a separate fleet model broken down into the following eight vehicle technologies:

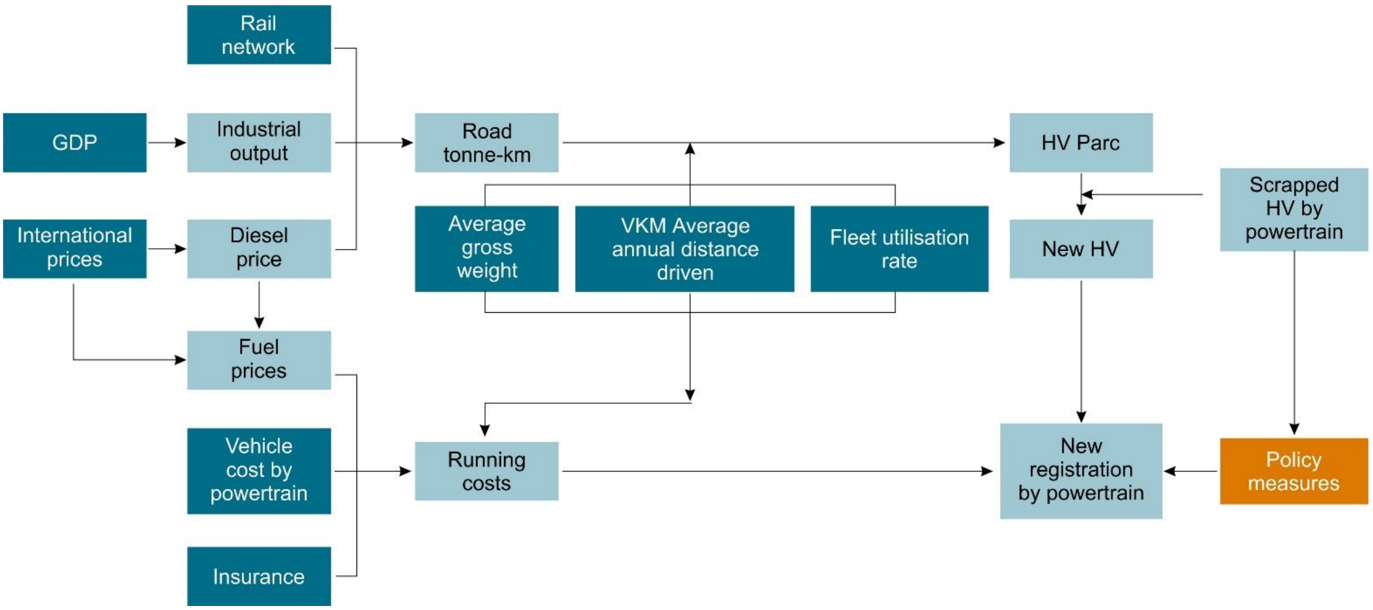
- Diesel
- Gasoline
- Full Hybrids: Diesel, Gasoline, Natural Gas (i.e. not plug-in)
- Plug-in Hybrid Electric Vehicles: Diesel, Gasoline, Natural Gas

- Pure Battery Electric Vehicles
- Natural Gas Vehicles
- LPG Vehicles
- Hydrogen fuel cell vehicles

Each vehicle technology is modelled in terms of new registrations, scrappage and the total on-road fleet, or parc. The fleet is then multiplied by the annual average distance driven and the average fuel efficiency for new and retained vehicles to determine the fuel consumption. The associated carbon dioxide emissions are modelled from the consumption both on a tank-to-wheel basis (i.e. based on the specific emissions from the vehicle technology) and on a well-to-wheel basis (i.e. taking account of the associated emissions in deriving the fuels that are then used by the vehicles).

Heavy Duty Fleet Model

The main income driver for freight transport is Tonnes of freight transported per km per year (tonnes-km), which is determined by the overall level of economic activity (GDP and industrial output) and fuel costs. Tonne-km of road freight is also inversely related to the development of the rail network, with rail a competitor to road freight.



The effective fleet is the fleet needed to move the tonne-km of freight. The difference with the actual fleet numbers is that there can be spare, or underutilised, capacity.

- $\text{Total Fleet} = \text{Effective Fleet} + \text{Spare Fleet}$
- $EffectiveFleet = \frac{Total\ tonne{-}km}{tonne{-}km\ of\ an\ average\ truck}$

- $Tonnekm\ of\ an\ average\ truck = Avg\ gross\ weight \times Annual\ Avg\ Distance\ Driven\ \times Utilisation\ Rate$

The inputs into tonne-km of an average truck are all operational factors:

- Average gross weight of a truck is calculated from the historic data set and has been consistent at around 30 tonnes
- Annual average distance driven for the average truck – regulation of driving hours and conditions and operator policy will impact the value
- Exogenous value linked to history
- Autonomous vehicles could increase the annual average distance driven, so can be used to test scenarios with automation
- Utilisation rate is a measure of how efficiently the effective fleet is utilised – it measures the percentage of the time the vehicles are loaded against total journeys (loaded and empty): this is around 70%. It compares the number of trucks of average gross tonnage (30) driving the average annual distance that are required to transport the total tonne-km of freight to the actual effective fleet
- Exogenous assumption – this could be adjusted to reflect the population density of the country – turnaround times and times between loads will impact this value
- Improved logistics could increase the utilisation rate, as could larger operations by reducing the number of small operators

Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km

Annual cost of driving per new vehicle

The annual cost of driving a new vehicle is broken down into three elements:

Fuel costs – this is calculated based on the retail fuel prices in each country and the efficiency of new vehicles and the annual distance driven

Maintenance costs (tyres, parts and servicing costs) – this is an exogenous input expressed as a cost per truck per km driven

Insurance and road tax costs – this is an exogenous input expressed as a cost per truck

The annual driving costs are unitised by dividing by the average distance driven to give a cost per 1000 km.

Total annual driving cost per new vehicle

The total driving cost is the sum of the levelized cost of the vehicle, fuel, maintenance, and insurance/road tax. The total levelized cost allows the model to make comparable comparisons across the technology types.

Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fuelling stations/points in comparison to the main historic technology option – in the case of heavy duty vehicles, diesel trucks. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

Total annual driving cost per new vehicle adjusted by the availability factor

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

Annual distance driven (road km)

The average distance driven is linked to the road tonne-km of freight moved and the average load, as well as the share of the time when loaded. There is also an exogenous add factor.

Energy consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

Inputs and Outputs

The key inputs to the model include:

- Industrial output and real GDP
- Road-tonne-km of freight moved
- Rail network and rail freight moved as competition for road freight
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated maintenance costs and road tax and insurance
- The retirement profile of the existing fleet of vehicles
- Fuel efficiency of new vehicles
- Fleet average load per truck and the percentage of time running when loaded
- Policy options to favour certain technologies and change the average road km driven

The key outputs are:

- Fleet of vehicles by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emissions

Medium and Light-Medium Duty Vehicles

The medium duty vehicle segment was split into two: Light-Medium (3.5 to 6.0 tonnes) and Medium-Heavy (6.0-15.0 tonnes). There is a strong relationship between light-medium vehicles and e-commerce, while medium-heavy are linked to the wider road freight transport demand and the development of the light-medium fleet – essentially the medium-heavy vehicles are helping to provide the freight moved by the light-medium vehicles.

LV are a function of:

- E-Commerce index is a driver for the internet's ability to support e-commerce. It is linked to e-commerce infrastructure development (coverage and performance of internet), which we relate to GDP per capita and the wider urban density of the country (urban population per country land area in sq-km) – less dense countries have a weaker e-commerce infrastructure for a given level of GDP per capita
- Density of urban areas (urban population per urban area in sq-km): How many people can be served within a given urban radius – the higher the greater the economic opportunity for LVs

MV are a function of:

- Road tonne-km – total road freight transported per year
- LV fleet – the LV fleet was found to be complementary to the MV fleet. The LV fleet is correlated with service sector value added (retail is part of the service sector) so only the LV fleet is included to avoid autocorrelation issues

Light Medium Duty Vehicles – LV (3.5-6 tonne)

Key drivers

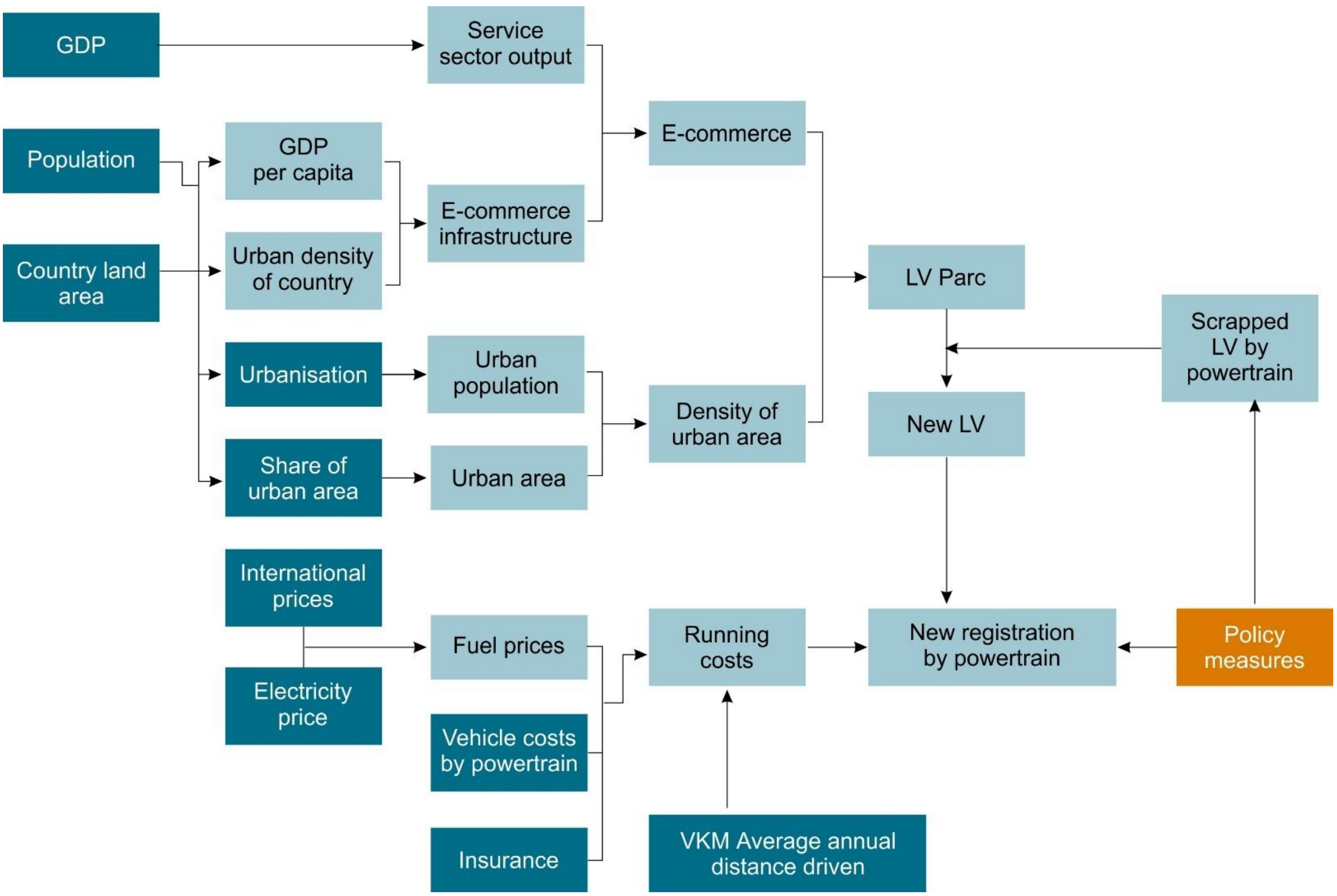
The development of the light-medium duty fleet is linked to the density of urban areas and to e-commerce. This category of vehicle is increasingly linked to home deliveries of retail goods, with the growth of on-line shopping a major component of that growth. The fleet development is therefore linked to the scale of the e-commerce business. The secondary factor is the number of customers that can be supplied within a given catchment area. The greater the urban density the greater the number of consumers that can be supplied.

E-commerce

The e-commerce index is itself a function of the total service sector output and the development of e-commerce infrastructure. The latter is both a function of average income (although that can be offset by government support for the development of the internet) and urban density of the country – the denser the easier it is to establish e-commerce retail in these areas.

Density of urban area

The density of urban areas is the urban population divided by the urban area. It gives an indication of the population level in a given catchment area for light-medium vehicles.



It was found that both the e-commerce and the density of urban areas were strongly correlated with the light-medium vehicle fleet, but the two drivers were themselves correlated. We, therefore, put the density of urban areas in the cross-section estimation and adjust to individual countries.

To avoid one-off changes in e-commerce from one year to the next, the three-year moving average was used. On average a 10% increase in e-commerce produces a 4% increase in the light-medium vehicle fleet.

In addition, we impose boundary conditions to the urban density coefficients:

- Lower bound 0.1
- Upper bound 0.7
- A 10% increase in the urban density would produce 1% to 7% increase in the light-medium vehicle fleet, with the average around 4%

Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km.

Annual cost of driving per new vehicle

The annual cost of driving a new vehicle is broken down into three elements:

- Fuel costs – this is calculated based on the retail fuel prices in each country and the efficiency of new vehicles and the annual distance driven
- Maintenance costs (tyres, parts and servicing costs) – this is an exogenous input expressed as a cost per vehicle per km driven
- Insurance and road tax costs – this is an exogenous input expressed as a cost per vehicle

The annual driving costs are unitised by dividing by the average distance driven to give a cost per 1000 km.

Total annual driving cost per new vehicle

The total driving cost is the sum of the levelized cost of the vehicle, fuel, maintenance, and insurance/road tax. The total levelized cost allows the model to make comparable comparisons across the technology types.

Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fuelling stations/points in comparison to the main historic technology option – in the case of light-medium duty vehicles, gasoline vans. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

Total annual driving cost per new vehicle adjusted by the availability factor

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

Annual distance driven (road km)

The average distance driven is linked to the historic distance driven adjusted for the average load, as well as the fuel prices. There is an option to specify a minimum threshold. As well as an exogenous add factor.

As the average load increases, so it is assumed that this will result in the average distance driven increasing (subject to an elasticity). The change in the retail price of fuel will also have an impact on the average distance driven, although this tends to be a short-run impact.

Energy consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

Inputs and Outputs

The key inputs to the model include:

- Service sector output
- E-commerce infrastructure
- Urban land area
- Urban population
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated maintenance costs and road tax and insurance
- The retirement profile of the existing fleet of vehicles
- Fuel efficiency of new vehicles
- Fleet average load per truck and the percentage of time running when loaded
- Policy options to favour certain technologies and change the average road km driven

The key outputs are:

- Fleet of vehicles by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emissions

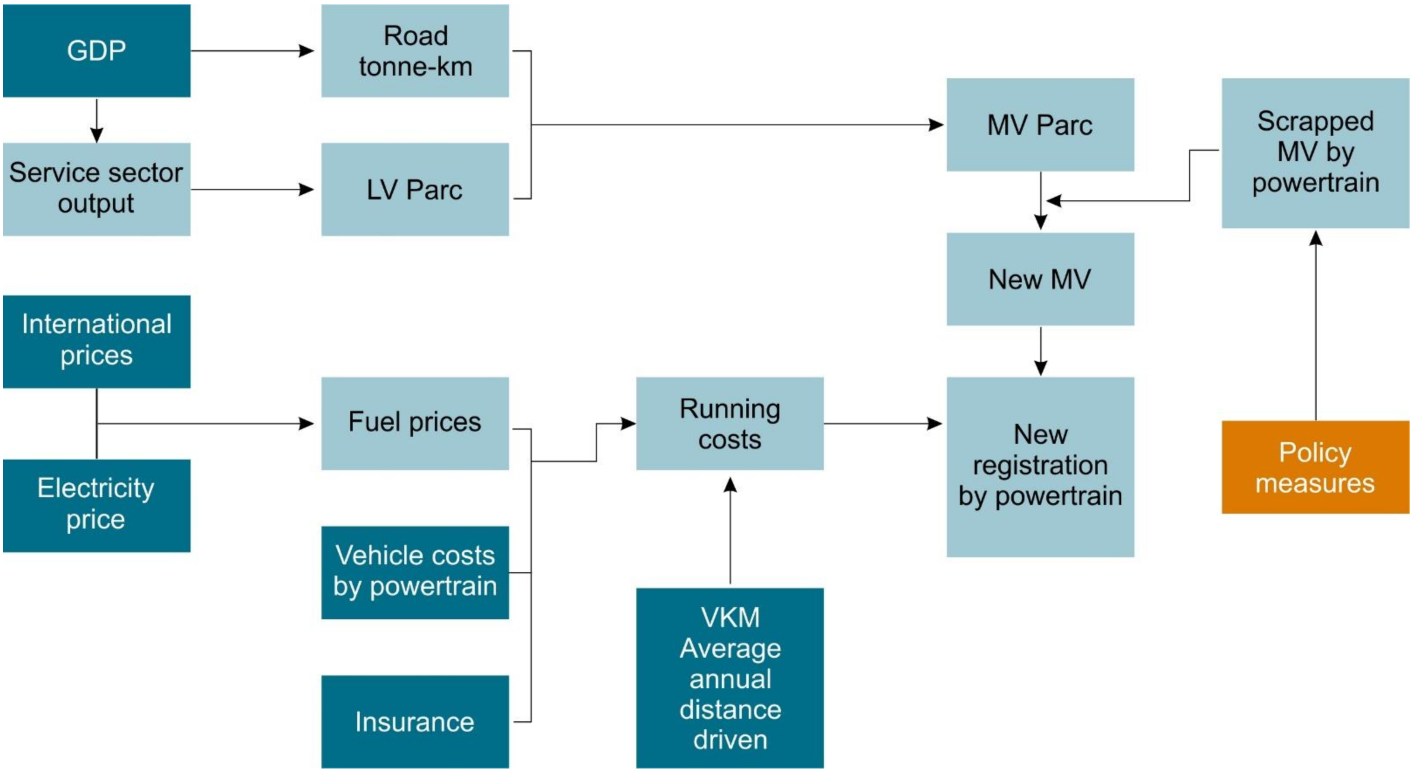
Medium Heavy Duty Vehicles – MV (6-15 tonne)

Key drivers

The development of the medium-heavy duty fleet is linked to the road freight moved (road tonne-kms) and the development of the light-medium vehicle fleet. As previously noted, the medium-heavy duty fleet was found to be complementary to the development of the light-medium vehicle fleet. As e-commerce increases and creates an increased demand for local distribution directly to consumers homes, and with it an increase in the light-medium vehicle fleet, so the need to service this last element of the supply chain increases and medium-heavy vehicles benefit in meeting that requirement, moving goods from regional distribution points to local distribution points.

Road tonne-km freight

As indicated above in the heavy-duty vehicle segment, road freight is a function of the overall level of economic activity (GDP and industrial output) and fuel costs. Tonne km is also inversely related to the development of the rail network, with rail a competitor to road freight.



MV market is strongly correlated with the LV market indicating they are complementary segments of the market. A 10% increase in the LV parc will lead to a 4% increase in MVs.

MV is also correlated with road tonne-kms. Three-year moving average is used to avoid the issue of any one year resulting in a sharp increase or decrease in the parc. A 10% increase in road tonne-km will lead to a 2%

increase in the MV fleet on average. The constant is included as a cross-section variable to reflect starting differences between countries

Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km

Annual cost of driving per new vehicle

The annual cost of driving a new vehicle is broken down into three elements:

- Fuel costs – this is calculated based on the retail fuel prices in each country and the efficiency of new vehicles and the annual distance driven
- Maintenance costs (tyres, parts and servicing costs) – this is an exogenous input expressed as a cost per vehicle per km driven
- Insurance and road tax costs – this is an exogenous input expressed as a cost per vehicle

The annual driving costs are unitised by dividing by the average distance driven to give a cost per 1000 km.

Total annual driving cost per new vehicle

The total driving cost is the sum of the levelized cost of the vehicle, fuel, maintenance, and insurance/road tax. The total levelized cost allows the model to make comparable comparisons across the technology types.

Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fuelling stations/points in comparison to the main historic technology option – in the case of medium-heavy duty vehicles, diesel trucks. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

Total annual driving cost per new vehicle adjusted by the availability factor

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

Annual distance driven (road km)

The average distance driven is linked to the historic distance driven adjusted for the average load, as well as the fuel prices. There is an option to specify a minimum threshold. As well as an exogenous add factor.

As the average load increases, so it is assumed that this will result in the average distance driven increasing (subject to an elasticity). The change in the retail price of fuel will also have an impact on the average distance driven, although this tends to be a short-run impact.

Energy consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

Inputs and Outputs

The key inputs to the model include:

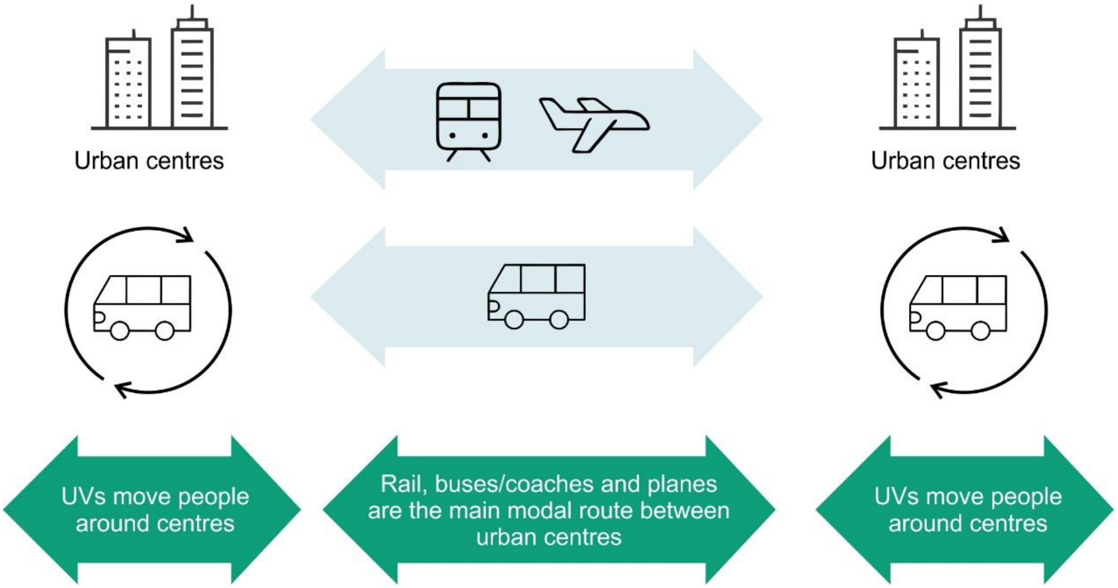
- Road-tonne-km of freight moved
- Light-medium vehicle fleet
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated maintenance costs and road tax and insurance
- The retirement profile of the existing fleet of vehicles
- Fuel efficiency of new vehicles
- Fleet average load per truck and the percentage of time running when loaded
- Policy options to favour certain technologies and change the average road km driven

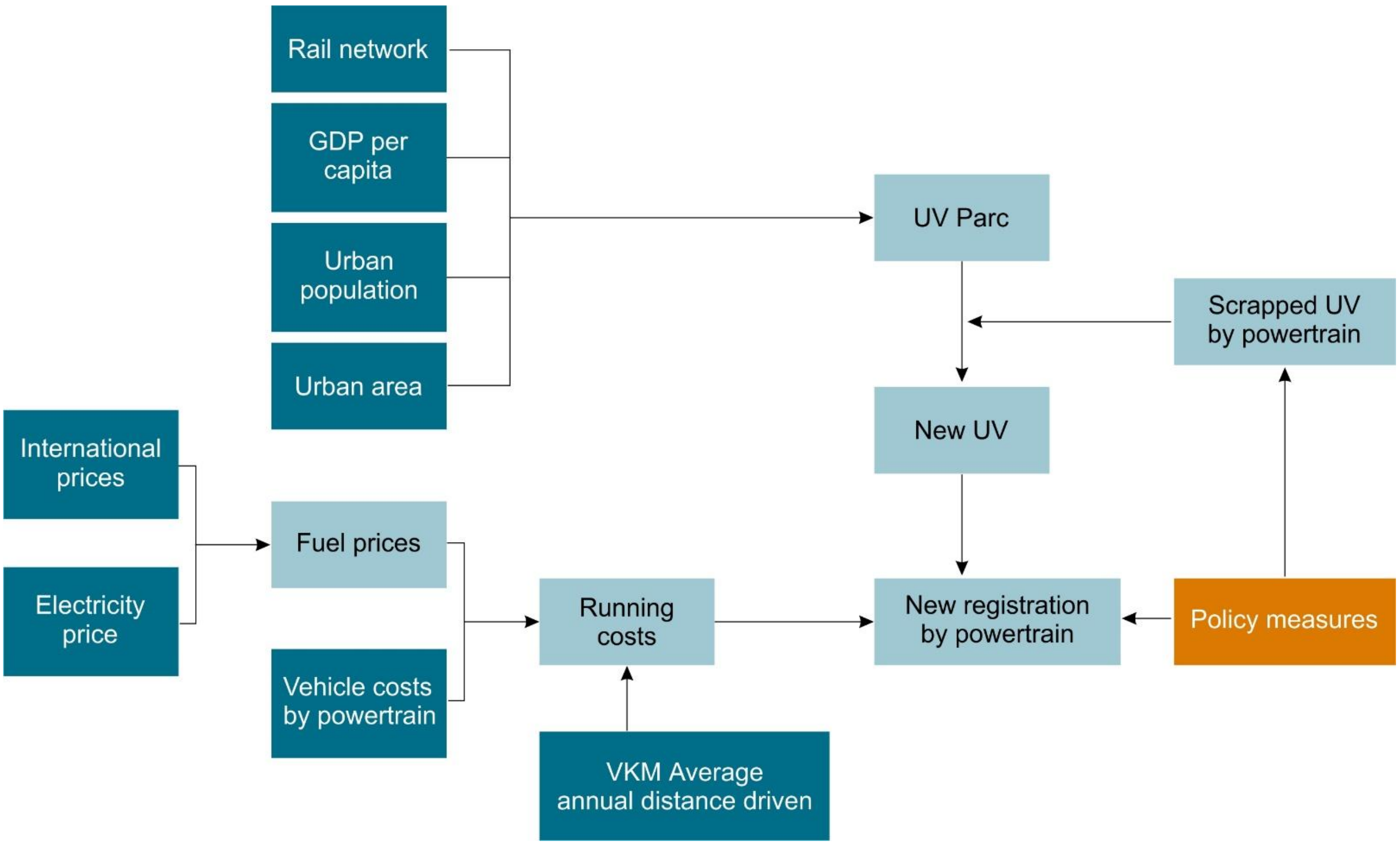
The key outputs are:

- Fleet of vehicles by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emissions

Utility Vehicle Model

The schematics below illustrate the Utility Vehicle (UV, 3.5-15 tons) model, which includes buses, coaches and refuse collection.


Urban centres
Urban centres
UVs move people around centres
Rail, buses/coaches and planes are the main modal route between urban centres
UVs move people around centres


Rail network
GDP per capita
Urban population
Urban area
UV Parc
Scrapped UV by powertrain
New UV
International prices
Electricity price
Fuel prices
Vehicle costs by powertrain
Running costs
New registration by powertrain
Policy measures
VKM Average annual distance driven

UV – function of:

- 3-year moving average of GDP per capita (positive coefficient)
- Urban population (positive coefficient)
- Rail network (positive coefficient suggesting that utility vehicles are complementary to the development of the rail network and not in competition – people need buses to connect to rail services)
- Urban area (positive coefficient) – utility vehicles fleet increases as the urban area increases. Urban area needs to be forecast for this model and for the MDV model segments

Ownership cost per vehicle

The costs of driving a vehicle are its upfront costs spread over the life of the vehicle at a discount rate related to commercial interest rates. The costs can include subsidies to support new technologies. Dividing the costs by the annual average distance driven provides a unit cost per 1000 km

Annual cost of driving per new vehicle

The annual cost of driving a new vehicle is broken down into three elements:

- Fuel costs – this is calculated based on the retail fuel prices in each country and the efficiency of new vehicles and the annual distance driven
- Maintenance costs (tyres, parts and servicing costs) – this is an exogenous input expressed as a cost per vehicle per km driven
- Insurance and road tax costs – this is an exogenous input expressed as a cost per vehicle

The annual driving costs are unitised by dividing by the average distance driven to give a cost per 1000 km.

Total annual driving cost per new vehicle

The total driving cost is the sum of the levelized cost of the vehicle, fuel, maintenance, and insurance/road tax. The total levelized cost allows the model to make comparable comparisons across the technology types.

Availability factor for vehicle types

The availability factor is a variable that is used to define how easy it is to own and operate the vehicle. It captures the coverage of vehicle fueling stations/points in comparison to the main historic technology option – in the case of utility vehicles, diesel vehicles. Without a network of charging points, consumers may be less willing to buy new electric vehicles even if the running cost is competitive with existing diesel vehicles. The availability factor takes this into account and provides a penalty price for these vehicle types. The availability factor is an exogenous time series that the user can change over time and by vehicle type.

Total annual driving cost per new vehicle adjusted by the availability factor

The adjusted total driving cost is the total driving cost divided by the availability factor and raised to the power of an exogenous time series gamma. If the availability factor is less than 1 it will increase the total driving cost for that vehicle type. In the first instance the availability factor is set to adjust the costs to reflect the share of new vehicle registrations. In this way the total adjusted cost becomes the shadow running cost.

The relative difference in the levelized total driving cost is used to allocate shares for new vehicle registrations. Rather than using a simple linear distribution function for the shares, a Weibull distribution function is used. The user can set the parameters for this function to give greater shares to the least cost technologies.

Annual distance driven (road km)

The average distance driven is linked to the historic values plus an exogenous adjustment factor. There is an option to specify a minimum threshold. As well as an exogenous add factor.

Energy consumption

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies and the annual average kilometers travelled per vehicle.

Inputs and Outputs

The key inputs to the model include:

- Real GDP per capita
- Urban population
- Urban land area and total land area
- Rail network as competition for buses and coaches
- Interest rates
- Retail fuel prices
- Cost of different vehicles and their associated maintenance costs and road tax and insurance
- The retirement profile of the existing fleet of vehicles
- Fuel efficiency of new vehicles
- Fleet average load per truck and the percentage of time running when loaded
- Policy options to favour certain technologies and change the average road km driven

The key outputs are:

- Fleet of vehicles by fuel-type of vehicle
- Annual distances driven
- Annual running cost of fuel-type of vehicles
- Average fuels efficiency by fuel-type
- Annual fuel consumption
- Carbon dioxide emission

Macro & demographic model

The existing macroeconomic and demographic sub-model contains SPGCI base case outlook and allows the user to run sensitivities to changes in global and national GDP, as well as the impact of global oil price changes.

Inputs and Outputs

The key inputs are:

- Base macro and demographic data assumptions
- Urbanisation rate
- Oil and carbon price assumptions

The key outputs for the road transport model are:

- GDP (real and nominal)
- Consumer expenditure (real and nominal)
- Industrial output
- Population – total and urban
- US dollar exchange rate
- Inflation – GDP deflator
- Interest rates

Retail fuel prices

SPGCI energy model has a pricing sub-model to convert international wholesale prices to national markets' retail prices. This is an important part of the model to provide the inputs to running costs as well as behavioral drivers such as road-km driven.

The model enables users to input the global oil price (Brent crude oil price) and a number of other international benchmark prices (ARA coal prices, natural gas prices, carbon prices etc.) and these flow through to the end-use retail prices in each country, reflecting the historic relationship between the international prices and national retail prices.

International benchmark prices

International benchmark prices are largely exogenously determined. However, for the scenarios it is important that all benchmark prices for a certain type of fuel are linked together. For example, there are four main crude prices in the model: Brent, WTI, Dubai and Urals. These marker crudes are price setters in different locations, but there is generally little difference between the crudes.

The base-case difference between the crudes is maintained for the scenarios, with the ability to adjust the difference exogenously. To achieve this, a single market crude is used as the main reference, in this case

Brent, from which the other crudes are determined. A similar approach is adopted with coal and carbon. These benchmark prices are then fed into the country-specific price calculations.

Crude Oil Prices

There are four market crude oil prices:

- Brent
- West Texas Intermediate (WTI)
- Dubai
- Urals

Brent is the main marker crude and is an exogenous input to the model. The other crudes are derived as simple differentials to Brent.

Oil Product Prices

There are seven petroleum products:

- Naphtha
- Gasoline
- LPG
- Jet Fuel
- Gasoil
- Low Sulphur Fuel Oil (LSFO)
- High Sulphur Fuel Oil (HSFO)

There are four main markets and their associated crude oil:

- US Gulf Coast (GCO) - WTI
- Singapore (SGP) - Dubai
- NW Europe (NWE) - Brent
- Mediterranean (MED) – Brent

Oil prices are based on the underlying crude oil prices (the pass through of crude price changes to oil product prices, which is estimated from a linear regression) and changes in the crack margin due to upgrading investments (i.e. investment in additional cracking capacity that impacts the international benchmark prices).

Natural Gas Prices

International benchmark gas prices tend to be endogenous to the model, either linked to oil product prices or the marginal cost of supply. In general, natural gas prices are either determined by one or more of the following options:

- Oil-indexed prices – gas prices change with changes to spot oil product prices;

- Regulated prices – gas prices are determined by the government
- Spot prices – gas prices are linked to the marginal cost of supply

Carbon Prices

There are five reference carbon prices considered:

- European Emission Trading Scheme (ETS) – EU Allowances (EUA)
- US trading System, e.g. California ETS/LCFS
- Japanese trading system
- Australia-New Zealand trading system
- South Korea – trading system

End-use retail prices

The various international benchmark prices are allocated to each country as a reference series. The data is converted from US$ into the local currency unit. Distribution costs and margins are added to the import price based on the historic relationship between the pre-tax prices and the international prices.

The appropriate taxes are added to the pre-tax values to arrive at the retail price. To this can be added the implied carbon price, if there is such a price and it applies to the specific sector. The intension is that the retail plus the carbon cost will reflect the actual cost faced by consumers and will be part of the price sensitivity of consumers.

- Oil prices: Import price + transport & margin + taxes + carbon price
- Natural gas prices: Import price + transport & margin + taxes + carbon price
- Electricity prices: Wholesale price + transport & margin + taxes
- Carbon price is not directly applied to the cost of the fuel but is an implied cost that we add so that it influences the substitution and efficiency choices. Assumptions will need to be made regarding any free allocation and whether this is passed through to consumers or whether the full opportunity cost is assumed. Additionally, assumptions need to be made concerning sectors covered by the cost – does it apply to industry and power only or transport and domestic as well? These options are exogenous inputs to the model.

Inputs and Outputs

The key inputs are:

- International benchmark marker prices
- International price differentials
- Exchange rates
- Deflators
- Excise taxes and VAT

The key outputs are:

- Retail prices for road transport fuels
- Retail prices plus implied carbon price
- Road transport fuels retail prices cover gasoline, diesel, LPG, natural gases and electricity

Data Sources

Car parc data from IHS Markit Automotive service, based on S&P Global POLK data.

Road transport energy consumption from the IEA's global annual energy statistics. Breakdown into road transport segments based on S&P Global estimates.

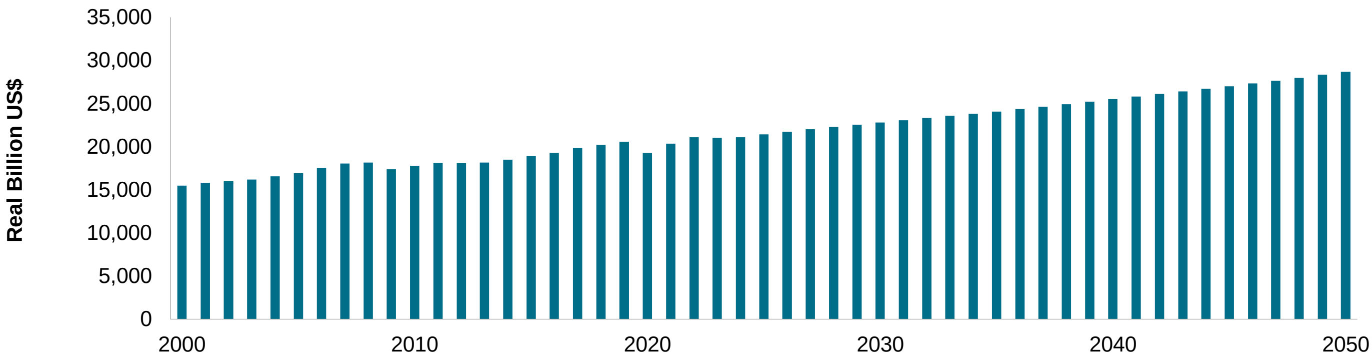
Road transport pricing from S&P Global data sources, including S&P Global OPUS.

Indicators and Assumptions

The table below summarizes of some of the key macro model indicator values that are utilized in the modelling of EU+ scenarios are shown below:

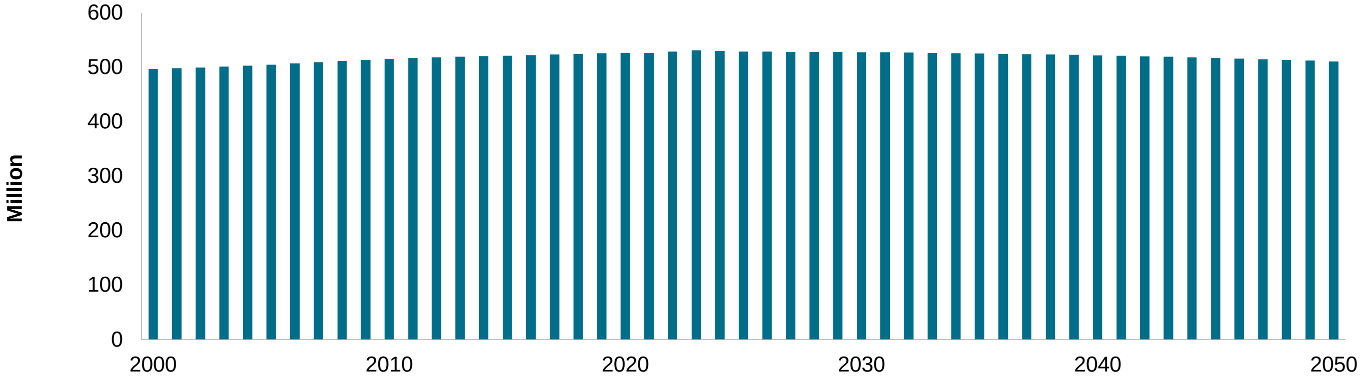
Indicators (region: EU+)	Unit	2030	2040	2050
GDP growth rate	%	1.16	1.22	1.26
Industrial output growth rate	%	1.06	0.92	1.15
Population: total growth rate	%	0.32	0.20	0.08
Population: urban growth rate	%	0.63	0.52	0.36

Macro Economic Indicators - Real GDP



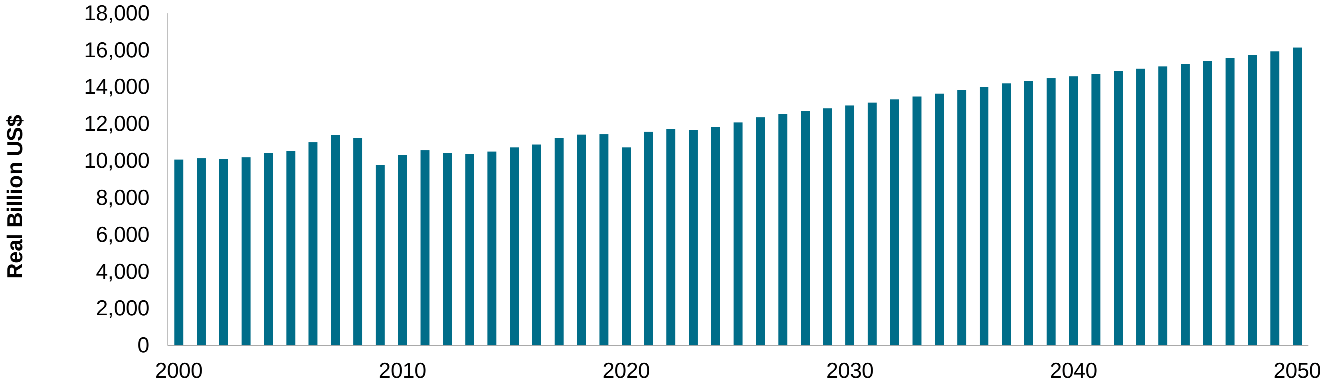
Source: S&P Global Commodity Insights.

Macro Economics Indicators - Population



Source: S&P Global Commodity Insights.

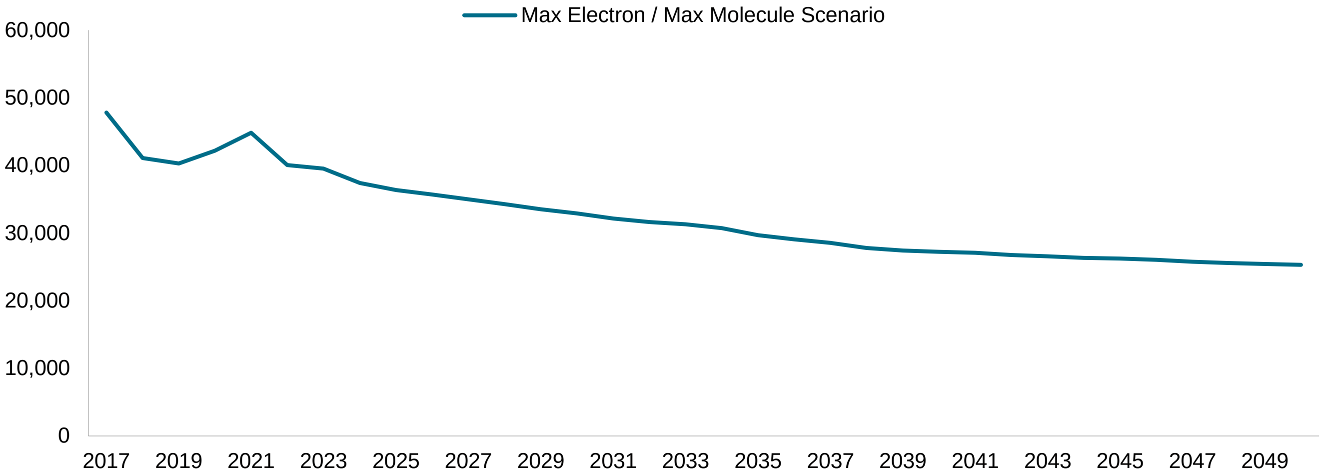
Macro Economics Indicators - Industrial Sector Output



Source: S&P Global Commodity Insights.

Although Industrial Sector output increases, within the Petrochemical Industry, production of virgin plastics under the Green Rules scenario is expected to fall. This is driven primarily by increased physical recycling of plastics, increased chemical recycling of plastics, and downward pressure on total plastic demand caused by either charges for, or bans on single-use plastic items. As a result, petrochemical feedstock demand shows a different trend to overall Industrial Sector output.

EU+ naphtha demand, thousand tonnes per annum



Data compiled 01 02 2024
Source: S&P Global Commodity Insights.

Annual numbers for Macro-Economic Factors are provided in the excel deliverables.

Road Transport

Road fuel consumption is determined as the sum of retained and new vehicles multiplied by their respective vehicle efficiencies (consumption per km) and the annual average kilometers travelled per vehicle.

Passenger Cars and LCV

Below are the key indicator values mentioned in the methodology chapter of road transport demand model:

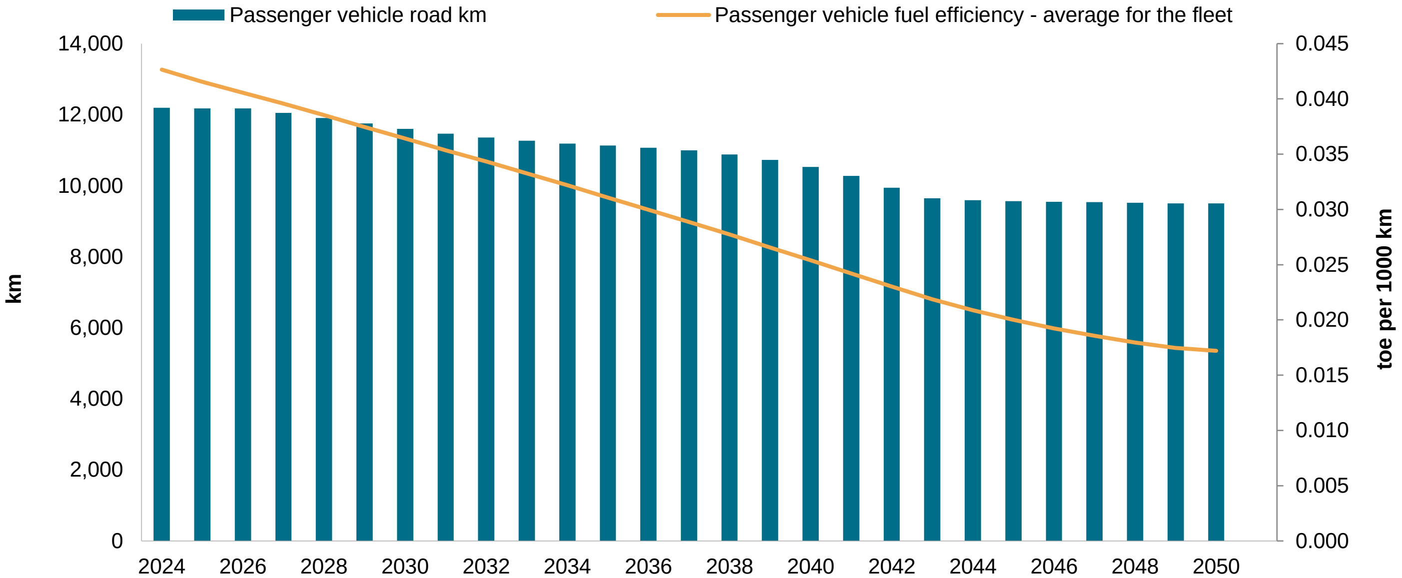
Indicators (region: EU+)	Unit	2030	2040	2050
No. of vehicles: passenger and LCV	Thousand	325,406	282,920	242,934
No. of vehicles growth rate: passenger and LCV	Percentage	-0.83%	-1.60%	-1.33%
Overall passenger and LCV scrappage rate	Percentage	5.25%	5.88%	5.16%
Passenger vehicle fuel efficiency: average for the fleet	Toe per 1,000 km	0.04	0.03	0.02
Passenger vehicle fuel efficiency: new cars	Toe per 1,000 km	0.02	0.01	0.01
LCV fuel efficiency: average for the fleet	Toe per 1,000 km	0.04	0.02	0.02
LCV fuel efficiency: new cars	Toe per 1,000 km	0.03	0.02	0.02

Indicators (region: EU+)	2030	2040	2050
Passenger vehicles scrappage rate: gasoline cars	7.4%	15.6%	16.2%
Passenger vehicles scrappage rate: diesel cars	7.4%	15.6%	16.2%
Passenger vehicles scrappage rate: LPG cars	4.1%	1.4%	1.0%
Passenger vehicles scrappage rate: CNG cars	4.1%	1.1%	1.0%
Passenger vehicles scrappage rate: hydrogen cars	2.1%	5.5%	5.8%
Passenger vehicles scrappage rate: BEV cars	0.3%	2.0%	3.9%
Passenger vehicles scrappage rate: HEV cars	0.5%	7.3%	19.4%
Passenger vehicles scrappage rate: PHEV cars	0.3%	2.0%	3.9%
LCV scrappage rate: gasoline cars	9.9%	25.5%	32.1%
LCV scrappage rate: diesel cars	18.1%	35.8%	40.6%
LCV scrappage rate: LPG cars	27.2%	9.5%	6.7%
LCV scrappage rate: CNG cars	5.5%	1.4%	1.6%
LCV scrappage rate: hydrogen cars	3.3%	5.5%	5.8%
LCV scrappage rate: BEV cars	0.5%	2.6%	5.3%
LCV scrappage rate: HEV cars	0.9%	12.4%	25.9%
LCV scrappage rate: PHEV cars	0.5%	2.7%	6.2%

In the Max Electron case, the ICE sales are banned post 2035 for passenger and light duty vehicles.

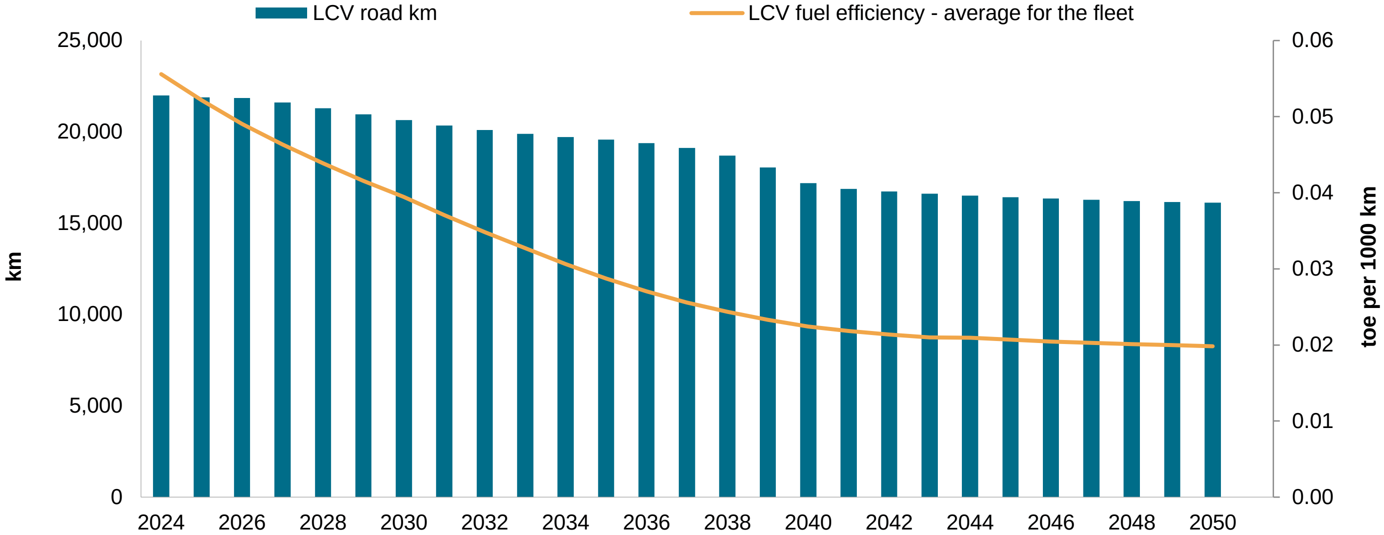
In the More Molecule case, PHEV sales are continued post 2035 and reach 45% of new vehicles sales in 2050.

Road Transportation Indicator- Passenger Vehicles Road kms and Fuel Economy



Source: S&P Global Commodity Insights.

Road Transportation Indicator- LCV Road kms and Fuel Economy



Source: S&P Global Commodity Insights.
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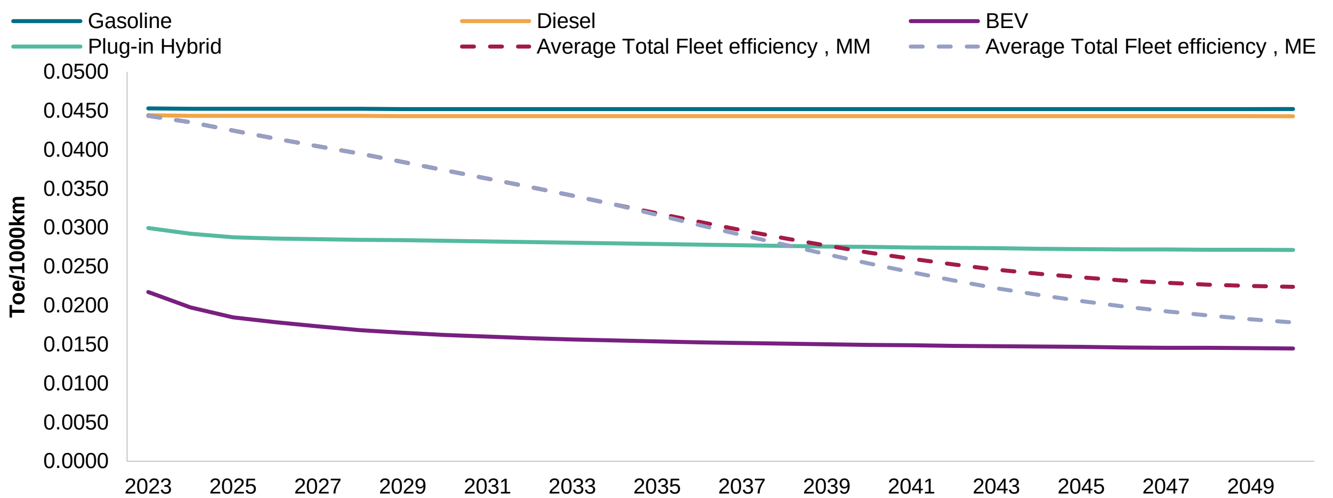
Passenger vehicle effeciency EU+ , Toe/1000 km



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.
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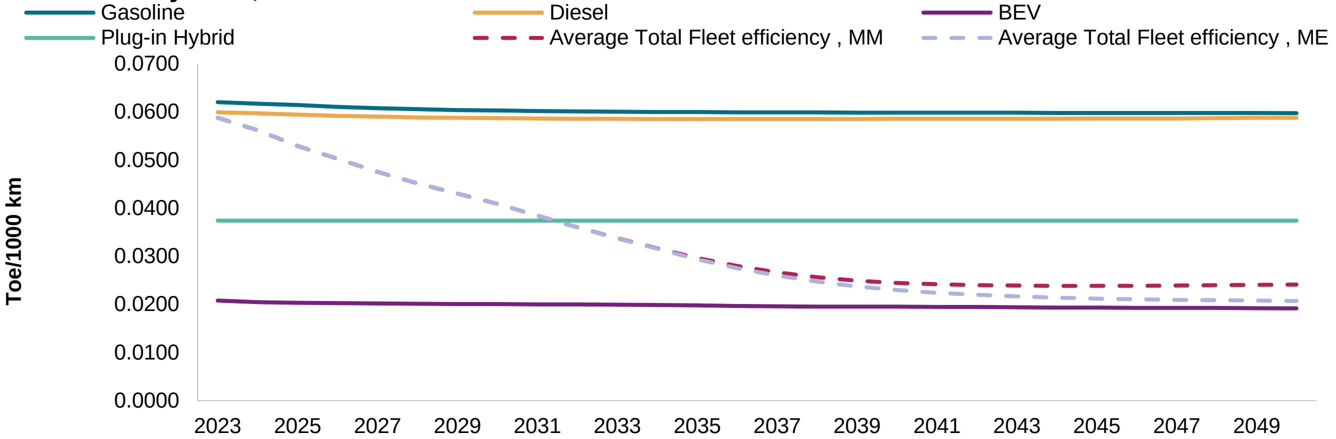
LCV efficiency EU+ , Toe/1000 km



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Heavy Road Transport

Heavy Road Transport Indicators are summarized in the tables below.

Indicators (region: EU+)	Unit	2030	2040	2050
Total freight	million tonne km	2,990,866	3,589,405	4,341,215
Road freight	million tonne km	2,155,634	1,947,785	1,646,739
Rail freight	million tonne km	835,232	1,641,620	2,694,476
Fleet details (3.5 to >15 tonne, classes 2b-8)				
Total fleet: GV	Number of vehicles	8,136,571	7,566,353	6,572,605
Total scrapped: GV	Number of vehicles	453,239	585,524	402,017
Total fleet: HV	Number of vehicles	4,703,566	3,848,530	2,591,053
Total new registrations: HV	Number of vehicles	276,322	309,401	149,135
Total scrapped: HV	Number of vehicles	327,837	442,457	248,523
Road km driven per year	km per year	1,876,631	2,046,370	2,530,092
Fuel consumption: total for HV	kToe	91,656	56,750	41,095
Medium duty vehicles (6.5 to 15 tonne, classes 4-7)				
Total fleet: MV	Number of vehicles	1,876,434	1,896,161	1,867,893
Total new registrations: MV	Number of vehicles	69,292	67,695	66,257
Total scrapped: MV	Number of vehicles	66,210	70,777	66,812
Road-km driven per year	km per year	692,090	625,356	587,654
Fuel Consumption: total for MV	kToe	5,450	3,809	2,576
Light medium duty vehicles (3.5 to 6.5 tonne, classes 2b-3)				
Total fleet: LV	Number of vehicles	930,553	1,002,815	1,061,786

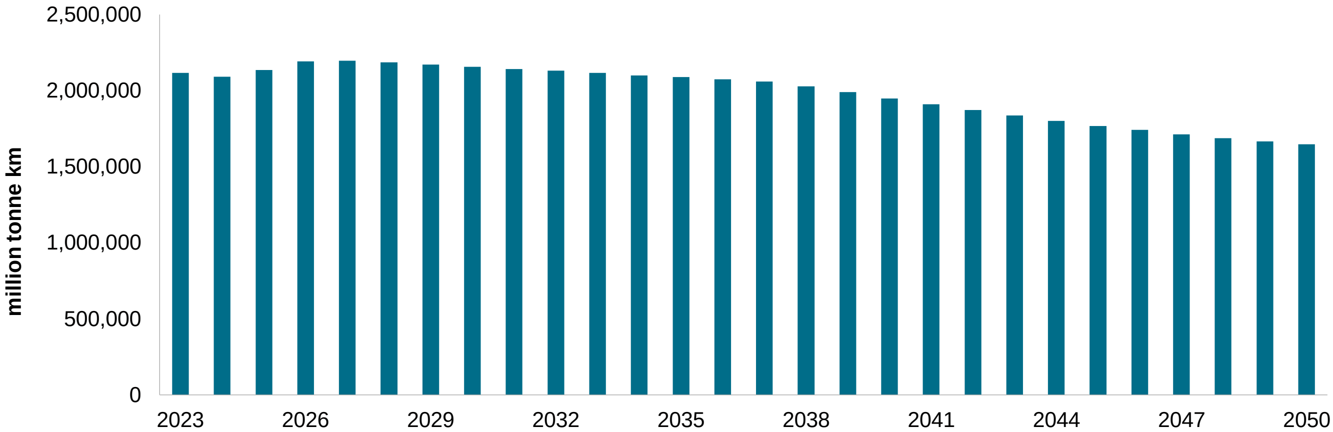
Indicators (region: EU+)	Unit	2030	2040	2050
Total new registrations: LV	Number of vehicles	35,729	37,573	41,791
Total scrapped: LV	Number of vehicles	29,034	32,418	34,536
Road-km driven per year	km per year	53,269	58,368	72,031

Drivers (region: EU+)	Unit	2030	2040	2050
HGV transport sector consumption of gasoline: efficiency improvement	ratio over previous year	0.99	0.99	0.99
HGV transport sector consumption of diesel: efficiency improvement	ratio over previous year	0.95	0.95	0.95
HGV transport sector consumption of LPG: efficiency improvement	ratio over previous year	0.99	0.99	0.99
HGV transport sector consumption of electricity: efficiency improvement	ratio over previous year	1.00	1.00	1.00
HGV transport sector consumption of natural gas: efficiency improvement	ratio over previous year	0.99	0.99	0.99
HGV transport sector consumption of hydrogen: efficiency improvement	ratio over previous year	1.00	1.00	1.00

In Max Electron case, Diesel GV sales are banned post 2035 and more BEVs are sold.

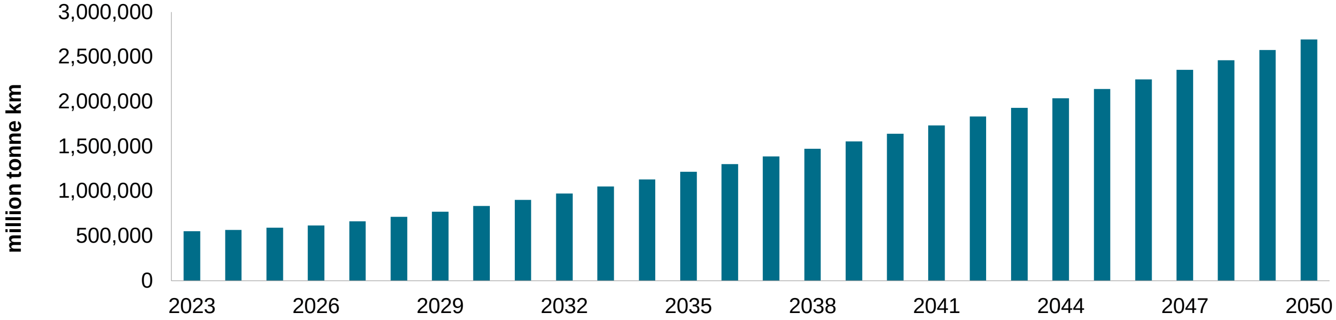
In More Molecule case, Diesel GV sales are continued post 2035, however fuel mix utilizes mostly biofuels and E-fuels in 2050 for ICE GV.

EU-27+ Total Heavy Road Transport Freight



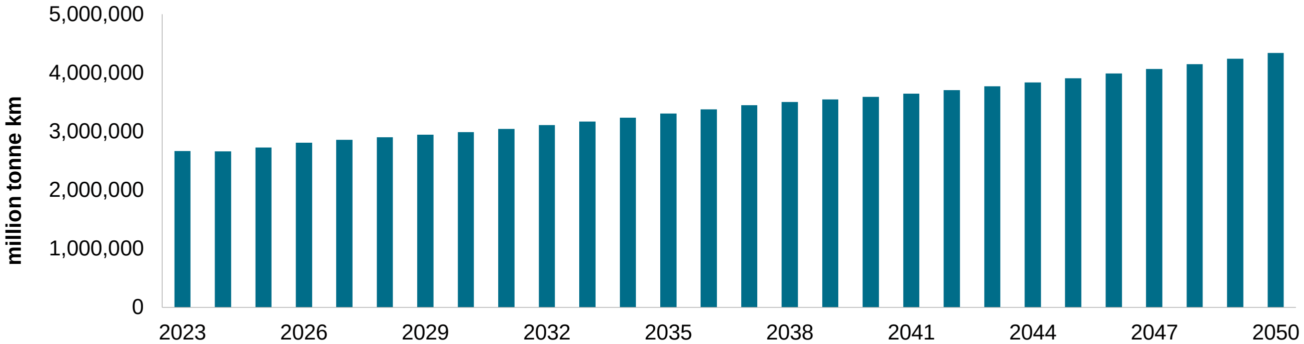
Source: S&P Global Commodity Insights.

EU-27+ Total Rail Freight



Source: S&P Global Commodity Insights.

EU+ Total Land Based Freight



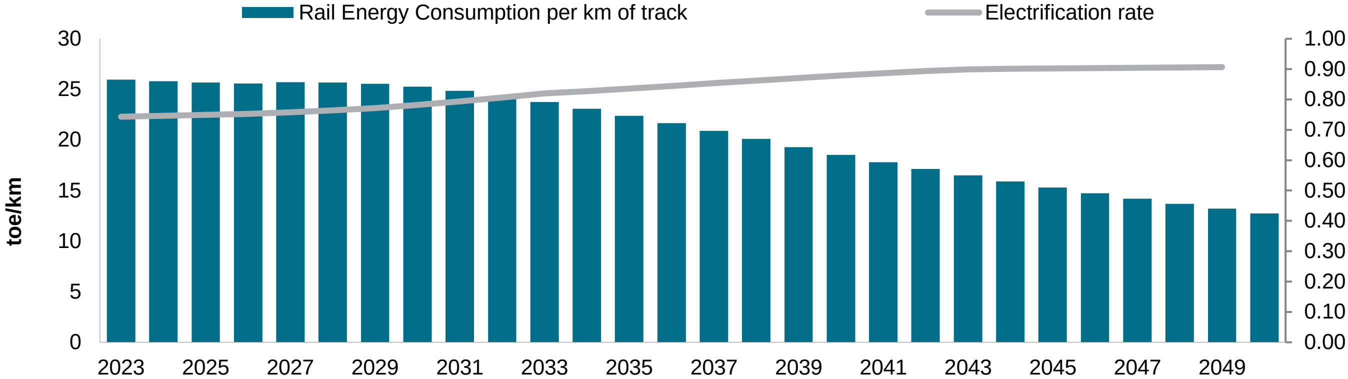
Source: S&P Global Commodity Insights.

Rail Transport

Rail fuel consumption is driven by the number of rail km travelled by the rail fleet. The rail km index is determined by the freight market, in terms if tonne km of freight moved by rail, and passenger km undertaken by rail, which is linked to consumer expenditure and inversely related to the number of bus km (i.e. the more bus km the fewer passenger rail km). These combined with the rail network size provide the key driver for rail demand. Rail network size (rail km) is exogenously determined. The increase in rail activity required to meet net-zero emission objective in 2050 represents a major challenge, which will require significant investment in the rail infrastructure.

Drivers (region: EU+)	Unit	2030	2040	2050
Electrification of railways	% coverage	77%	87%	91%
Rail freight	Million tonne km	835232	1641620	2694476
Energy consumption per tonne km (rail)	toe/million tonne-km	9.82	7.06	5.58
Rail energy consumption per km of track	toe/km	25.26	18.51	12.74

Rail Transportation Indicator- Energy Consumption per km of Track and Electrification Rate



Source: S&P Global Commodity Insights.

Aviation

Aviation is broken down into international and domestic aviation demand. It is assumed that flights within a country are predominately driven by domestic demand and is, therefore, linked to individual wealth. Demand is a function of average income, the price of jet fuel and efficiency improvements.

For international aviation flights the wider state of the economy (total GDP) is used as the driver as it relates to both wealth impacts for international tourist and trade in goods. International and domestic have been made distinct in order to allocate the energy-related CO_2 emissions.

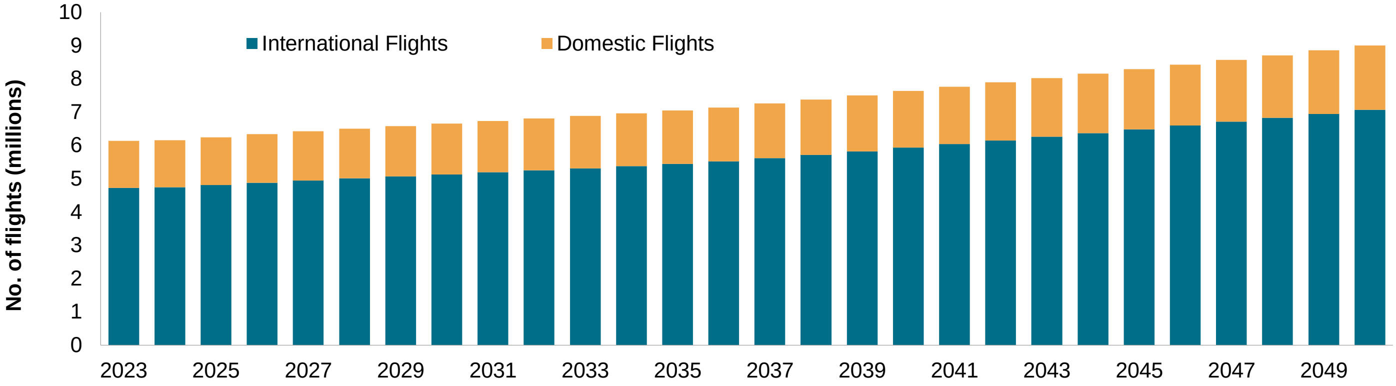
Future growth in aviation demand for jet fuel therefore can be determined as a function of GDP and its associated coefficient that is adjusted for overall efficiency improvements. We expect that LNG for aviation will not become commercially viable over the forecast period, and so we exclude this option from the demand modelling and maintain jet fuel (including SAF) as the only mainstream liquid aviation fuel.

Indicators (region: EU+)	Unit	2030	2040	2050
Total No of flights	Million	6.65	7.63	9.01
Domestic flights	Million	5.13	5.93	7.07
International flights	Million	1.52	1.70	1.93
Fuel consumption/flight	toe per flight	9.54	7.57	5.58
International fuel consumption per flight	toe per flight	10.85	8.52	6.18
Domestic fuel consumption per flight	toe per flight	5.08	4.22	3.33
Exogenous efficiency improvement	%	2%	2.2%	2.5%

In the Max Electron Case and More Molecule Case for aviation sector, the base case (i.e. Green Rules Case) is modified to ensure these scenarios meet the Refuel Aviation's overall SAF Targets. It is assumed that synthetic fuels will achieve the minimum targets mentioned in the policy and the remaining SAF demand is bio-based SAF. Overall, the target is for SAF to constitute 70% of total aviation demand by 2050.

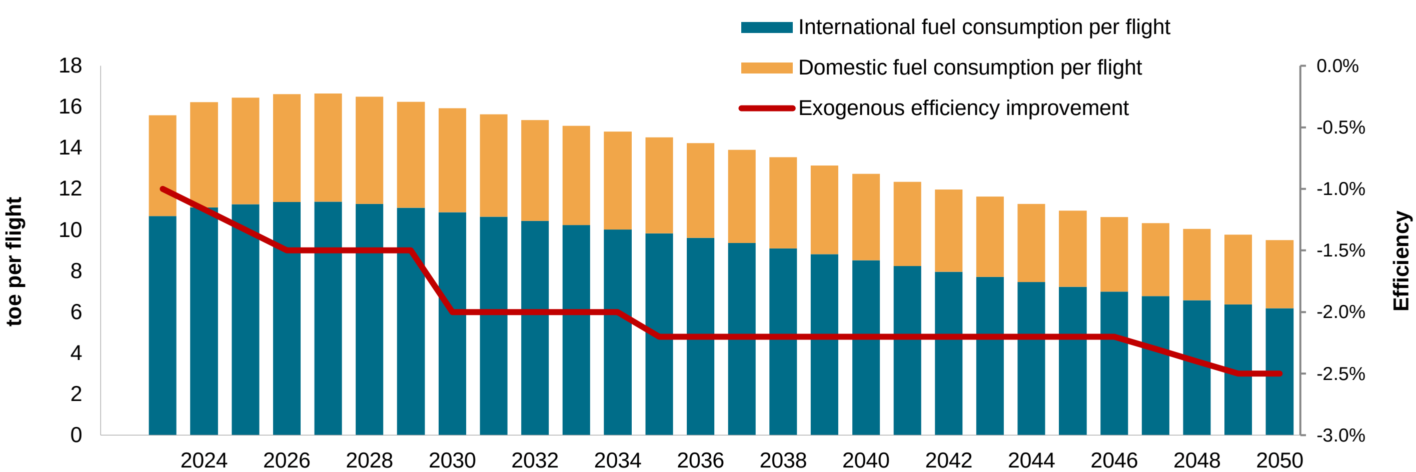
In More Molecule, electricity demand is removed from the fuel mix in aviation sector and is compensated by additional jet fuel energy demand, keeping the SAF target at 70% and the remainder fossil fuel jet.

Aviation Transportation Indicator- Domestic and International Flights



Source: S&P Global Commodity Insights.

Aviation Transportation Indicator-Fuel Consumption per Domestic and International Flight



Source: S&P Global Commodity Insights.

Maritime

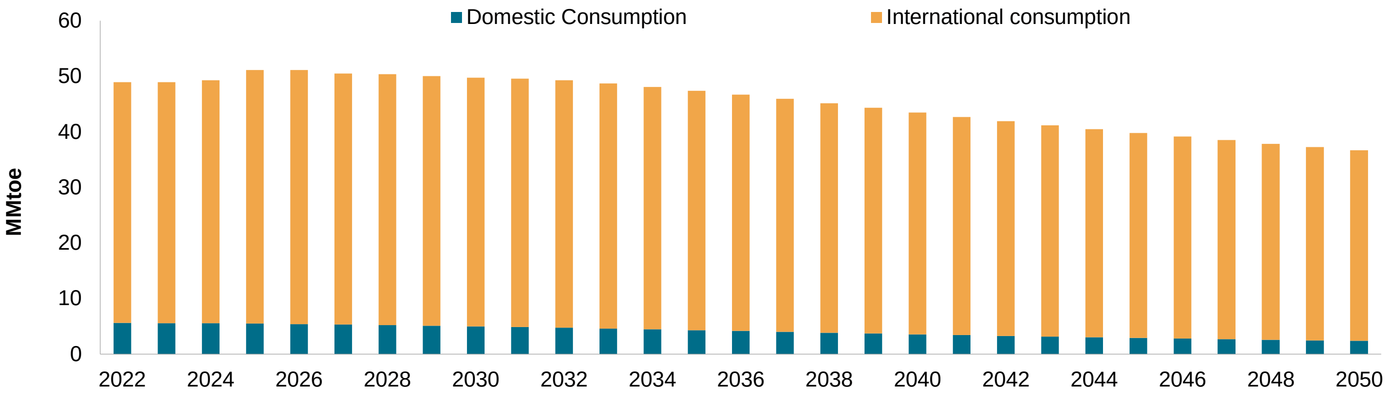
International bunkers demand is determined as a function of international trade. It is assumed that international bunkers are primarily heavy fuel oil with some marine diesel, but these are replaced in the future by lower carbon solutions.

The restrictions on the sulphur content of fuel oil to be used in shipping and FuelEU Maritime are opening the prospect for other fuels to enter the market, including low carbon fuels.

Domestic shipping demand is related to inland waterways and inshore areas. It includes a freight transport component that would depend on industrial output as well as a passenger traffic component that is linked to the population numbers. Thus, the drivers are industrial output, population, and efficiency improvements. It is assumed that domestic shipping uses marine diesel, LNG and low carbon fuels mix.

Indicators (region: EU+)	Unit	2030	2040	2050
Domestic consumption	MMToe	5.02	3.57	2.38
International consumption	MMToe	44.74	39.93	34.29
Efficiency factor for international marine transport	Multiplicative	0.98	0.97	0.95
Efficiency factor for domestic marine transport	Multiplicative	0.98	0.96	0.96

Maritime Transportation Indicator- Domestic and International Bunker Consumption



Source: S&P Global Commodity Insights.
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In Max Electron and More Molecule scenarios for the maritime sector, ReFuelEU maritime targets are achieved, and the fuel mix meets the emissions target specified in the policy for 2050. In the More Molecule Case, the electricity demand is removed from the fuel mix in maritime sector and replaced with fuels.

Feedstocks

Feedstocks refer to the use of hydrocarbons as a raw material and not for their energy content. Feedstocks covers both petrochemical uses and fertilizer production. Feedstock energy embedded is linked to the development of the feedstock sector output and agricultural output, the former linked to general feedstock demand and the latter to fertiliser demand.

Demand for virgin feedstocks will start to decline over time as both the mechanical and chemical recycling rate of finished plastics increases.

Demand for traditional chemical products will decline due to changes in consumer behavior/demand, supported by government legislation such as a shift away from plastic products due to banning single-use applications.

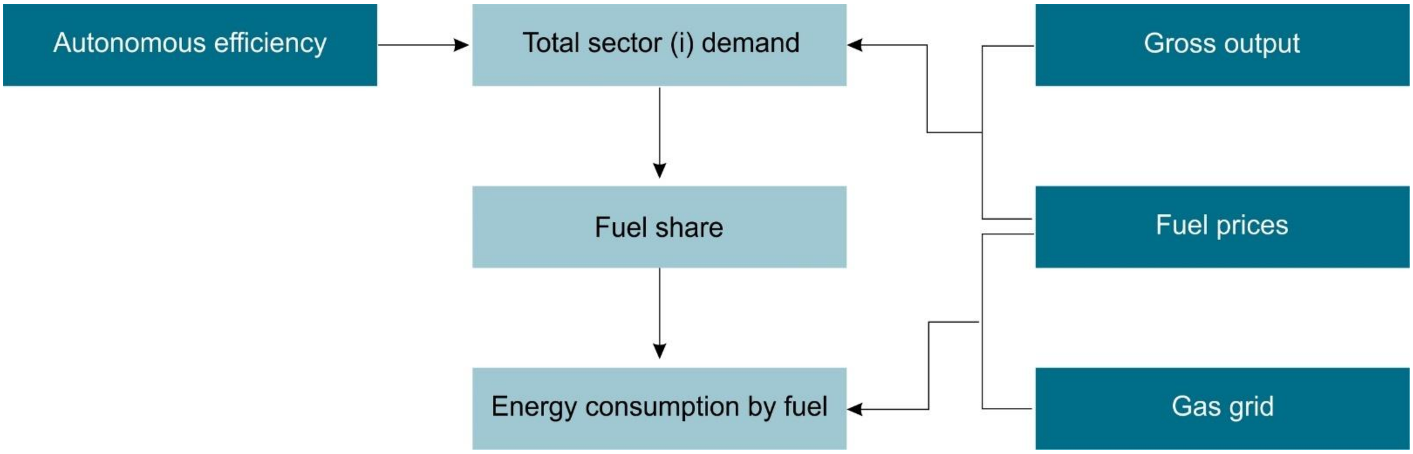
We also expect some increase in direct crude to chemicals production to partly offset decline in naphtha use. It may be worth noting that the fall in demand for feedstocks will be much smaller than that for main-fuels refined products, and as a result the naphtha yield in refining is expected to increase.

Natural gas feedstocks are also subject to the domestic gas production projection capacity i.e. the potential gas output. If feedstocks represent more than a trigger percentage (50% as an initial estimate) of the total gas production capacity and the production capacity is declining, then we might expect the use of gas in feedstocks to also decline.

Industry Sector Demand

A schematic representation of the industrial energy sub-models (excluding the iron & steel sector sub-models) is shown below. For each sub-sector there is a main income driver represented by the sectors gross output, and a substitution drive represented by energy prices (the marginal price including the implied cost of carbon).

Key factors to predict demands are the gross output of the sector, fuel prices and autonomous efficiency.



(i) stands for the individual sub-sectors.

The sub-sectors to be covered are:

- Chemicals
- Construction
- Mining & Quarrying
- Non-Ferrous Metals
- Non-Metallic Minerals
- Other Manufacturing

Energy demand by industrial sub-sector is determined as a function of the sub-sector activity driver, the change in consumption due to energy savings (which is a function of the energy price) and autonomous energy efficiency improvements.

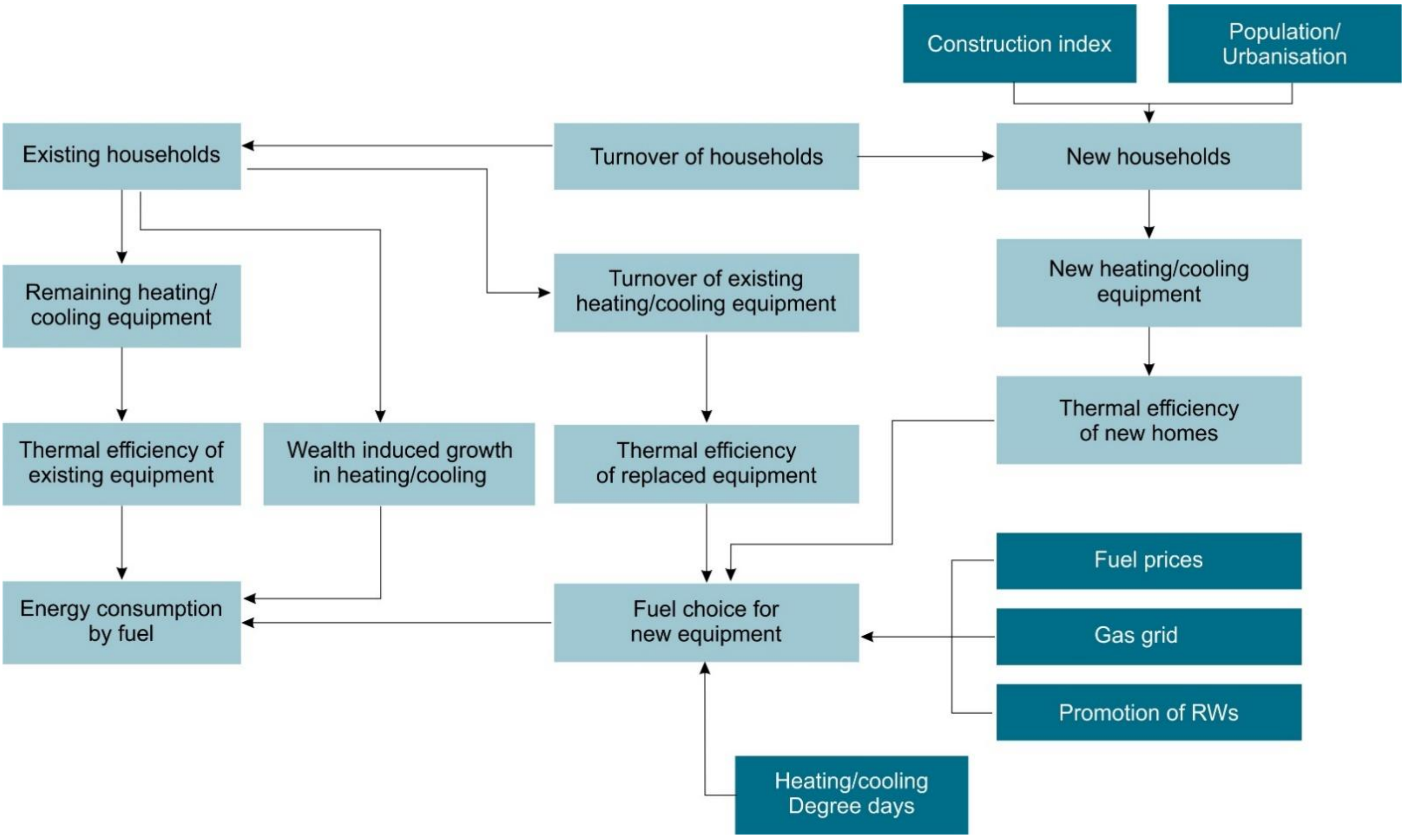
Indicators (region: EU+)	Unit	2030	2040	2050
Iron and steel sector output	Real million US$	238268	254832	270061
Chemical sector output	Real million US$	207763	235466	265393
Construction sector output	Real million US$	2875164	3260624	3637516
Fertiliser sector output	Real million US$	28083	33298	39271
Mining and quarrying sector output	Real million US$	268868	253540	235783
Non-ferrous metals sector output	Real million US$	200604	217840	234307
Non-metallic minerals sector output	Real million US$	319111	355680	387668
Other manufacturing sector output	Real million US$	8863752	9981121	11069170

Residential Sector

Residential energy demand is broken down into two main components:

- Substitutable energy demand – space conditioning, water heating, and cooking where there are a range of fuels that can be used
- Non-substitutable energy demand – electrical appliances and lighting where electricity is the unique energy supply

Below is a schematic representation of the various components of the residential energy demand model. The model looks at changes in housing stock, the competition among fuels for choice of new energy-using equipment based on improvements in relative efficiency and relative price changes to determine future demand by fuel.



Non-substitutable electricity consumption is that used for electrical appliances and lighting. The growth in electrical appliances and lighting is a function of the growth in disposable income. Either disposable income can be used directly or a proxy such as consumer expenditure or GDP per capita may be used as a growth metric.

Indicators (region: EU+)	Unit	2030	2040	2050
Number of households	Million	241	246	248
New build	Million	2.26	1.58	1.29
Population	Million	527	522	510
Consumer expenditure	Real million US$	12475	14164	15933
Efficiency deterioration of existing equipment	%	0.3%	0.3%	0.3%
Turnover of existing equipment	%	6.5%	9.5%	10.8%
Efficiency improvement of new housing	%	0.4%	0.4%	0.4%
Efficiency improvement of new equipment	%	0.4%	0.4%	0.4%

Commercial Sector

Commercial energy demand is broken down into two components:

- Non-electric energy demand – space/water heating equipment where there is a choice of fuels that could be used
- Country-level electricity demand

The main economic driver is GDP in the commercial sector, with the second order driver being commercial buildings. The table below shows the various components of the commercial sector demand model. The model looks at the turnover the existing stock of commercial buildings well as the development from new commercial floor space. Efficiency assumptions are same as residential sector.

Indicators (region: EU+)	Unit	2030	2040	2050
Number of employees	Million	249	248	247
Service sector output	Real million US$	15099672	17169052	19283973
Commercial floor space	Million square feet	862	894	921
New commercial floor space	Million square feet	9.20	8.82	8.73

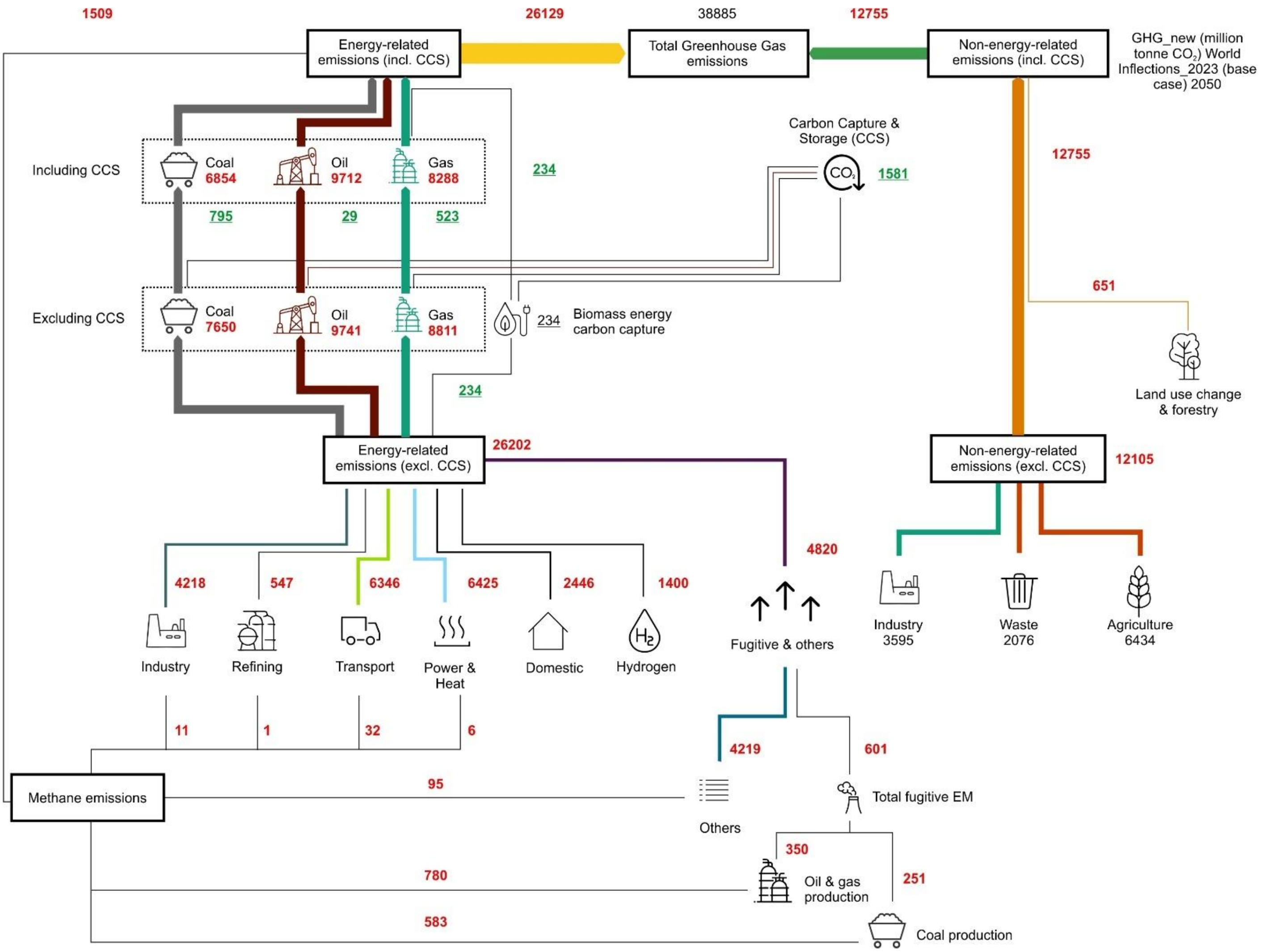
Agriculture Demand

It is intended to model the agricultural sector in a simplified manner, with a separation between the use of electricity and other energies (primarily diesel demand). Energy demand in the sector is linked to the gross output in agriculture, the fuel price and an autonomous efficiency factor.

Indicators (region: EU+)	Unit	2030	2040	2050
Agricultural sector output	Real million US$	666703	703099	728227

Emissions model

Greenhouse gas emissions are calculated in tonnes of CO2-equivalent using a global warming potential of 100 years. Emissions are divided between energy-related emissions and non-energy emissions. The schematic below shows the GHG emission aggregation process. This example shows 2050 emissions under S&P Globals' 2023 base case Inflections scenario.



Energy-related emissions are derived from the fossil fuel consumption by sector multiplied by the CO2 content of the fuels. In addition, non-CO2 energy-related emissions are included, e.g. nitrous-oxide (N2O), methane (CH4) and fluorocarbon-gases.

The International Panel on Climate Change (IPCC) guidelines on emission reporting are used as the basis for calculating GHG emissions from the energy sector. Emission factors are calculated for each fuel using the

IPCC methodology and applied to the energy balance data for both the history and projections. The CO_2 emissions from energy are detailed in the section below.

Non-Energy GHG Emissions

Non-energy related emissions are broken down into four categories:

- Agricultural
- Waste
- Industrial processes
- Land-use, land-use changes and forestry

Agriculture

The agricultural data is exclusive of energy use and comes from the Food and Agricultural Organisation (FAO). The following domains are identified by the FAO that make up the non-energy agricultural emissions:

- Enteric fermentation – methane from ruminant animals
- Manure management
- Rice cultivation
- Synthetic fertilizers
- Manure applied to soils
- Manure left on pasture
- Crop residues
- Cultivation of organic crops
- Burning - crop residues
- Burning – savanna

The FAO provide the following comment on total agriculture GHG emissions:

> "Agriculture Total contains all the emissions produced in the different agricultural emissions sub-domains, providing a picture of the contribution to the total amount of GHG emissions from agriculture. GHG emissions from agriculture consist of non-CO_2 gases, namely methane (CH_4) and nitrous oxide (N_2O), produced by crop and livestock production and management activities. Computed at Tier 1 following IPCC Guidelines for National GHG Inventories; available by country, with global coverage and relative to the period 1990 to present, with annual updates, and projections for 2030 and 2050."

Industrial Processes

Non-energy Industrial Processes sector includes:

- CO_2 emissions from Cement Manufacture (CDIAC; Boden et al., 2015)
- N_2O emissions from Adipic and Nitric Acid Production (EPA, 2012)

- N2O and CH4 emissions from Other Industrial (non-agriculture) (EPA, 2012)
- F-gases: HFCs, PFCs, and SF6 (EPA, 2012)

Waste

Non-energy Waste sector includes CH4 and N2O emission from the following activities:

- CH4 from Landfills (Solid Waste) (EPA, 2012)
- CH4 from Wastewater Treatment (EPA, 2012)
- N2O from Human Sewage (EPA, 2012)
- CH4 and N2O from Other (Waste) (EPA, 2012)

Land-Use, Land-Use Change and Forestry (LULUCF)

Land-Use and Forestry are again non-energy emissions and have the following domains with historic data from the FAO:

- Land Use Total
- Forest Land
- Cropland
- Grassland
- Burning – Biomass
- Forestry production and trade - forest products production, import and export statistics from 1961 onwards
- Forestry trade flows

In addition, country-specific carbon prices are used to drive emissions towards a theoretical maximum emission reduction potential. The higher the carbon price the faster the shift towards the maximum reduction potential. However, a time delay is added by estimating the relationship to the ten-year moving average carbon price. This smooths out the carbon price trend and prevents sharp price increases from leading to too fast an increase in the same year, given the delays in implementation and the need for sustained price incentives.

The carbon price equating to the maximum potential (kmaxrp$CO_2$$) can itself be related to the ratio of urban land area to total land area. The higher the ratio the higher the price. Alternatively, one can consider that the ratio of the rural area to total area is inversely related to the maximum carbon price – the lower the rural-to-total land area ratio the higher the price and the higher the rural-to-total ratio the lower the price.

In addition, some areas are not suitable for planting trees, grasses or other vegetation. In some countries the barren area is very large. We can use the share of barren land and combine it with the urban area share to get a view on the percentage of the land area that is not suitable for vegetation.

When almost all the land is available then the carbon price that equates with the maximum LUCF potential is set at US$300/t$CO_2$. As the available land declines as a share of the total land area so the maximums carbon price increases in an exponential manner. If none of the land area is available, then the maximum carbon price is set at US$1,500/t$CO_2$.

The maximum emission reduction potential is based on estimates from the IPCC Natural Climate Solutions (Table S3. Country level maximum mitigation potential with safeguards for 8 NCS pathways).

Energy related emissions

Emissions of carbon dioxide is calculated by each fossil fuel type, including oil by product and solid fuels by lignite and hard coal, for each of the end-use sectors, including industry sub-sectors, as well as for power generation.

Carbon capture use and storage is assessed at the sector level and the CO2 savings calculated based on the share of emissions that are sequestered.

Emissions are aggregated by fuel type and sector totals. The sum of the emissions by sector is the total emission and matches the sum of the totals by fuel.

Sector Emissions of CO_2				
Residential	**Commercial**	**Industrial and refining**	**Transport**	**Power/ heat generation**
Gas diesel oil	Gas diesel oil	Gas diesel oil	Gasoline	Diesel turbine
LPG	LPG	LPG	On-road diesel	HFO steam turbine
Residual oil	Residual oil	Residual oil	Rail diesel	Gas CT and gas CC
Other oils	Other oils	Other oils	LPG	Lignite steam
Natural gas	Natural gas	Natural gas	Jet fuel	Hard coal seam
Coal	Coal	Coal	Domestic marine diesel	Hard coal gasification
Biomass	Biomass	Biomass	Domestic marine HFO	Biomass
		Naphtha	International marine diesel	
			International marine HFO	
			Biodiesel	
			Bio-gasoline	

Emission factors used in the CO_2 model:

		Tonne of CO_2/toe
Crude oil	co2fCRU	3.0695
Motor gasoline	co2fGSL	2.8978
Kerosene	co2fKRS	3.0067
Jet	co2fJTF	3.0067
Gas/diesel oil	co2fGDO	3.0988
Residual fuel oil	co2fRFO	3.2370
Liquefied petroleum gases	co2fLPG	2.6382
Naphtha	co2fNPH	3.0695
Other petroleum products	co2fOLQ	3.0695
Hard coal	co2fHCL	3.9573
Lignite	co2fLIG	4.2337
Natural gas	co2fNGS	2.3492
Biomass(*)	Co2fCRW	4.6053

* Biomass emissions are generally assumed to be carbon neutral as we assume biomass is from sustainable sources. What is consumed is regrown, thus absorbing the emissions. However, where biomass emissions are captured and sequestered, there is a net saving and the emission saving is calculated using the emission factor shown in the table.

Note: Biofuels (biodiesel and bio-gasoline) net emissions are assumed to be 23g of CO_2/MJ in 2020. They are expected to gradually reduce to 5.5 g of CO_2/MJ by 2050. This assumes that the production of biofuels will become more sustainable over time.

Emissions factors for vehicle emissions from power train electricity, hydrogen and hydrogen derivatives are considered zero in the CO_2 model.

Methane related emissions

Emissions of methane are already incorporated into the non-energy GHG emissions. However, this is not the case for energy-related emissions. The methane emissions need to be added to the energy-related CO2 emissions to get the complete energy-related GHG emissions.

Methane emissions are derived from the sector level fuel consumption. Historic estimations are made between the sector methane emissions and the fossil-fuel energies consumed (coal, natural gas and oil). The coefficients are then used to estimate the methane emissions in the future.

The historic data comes from the EDGAR dataset (Reference: European Commission, Joint Research Centre (EC-JRC)/Netherlands Environmental Assessment Agency (PBL). Emissions Database for Global Atmospheric Research (EDGAR), release EDGAR v5.0 (1970 - 2015) of November 2019.)

Max Electron Scenario

In the development of the Max Electron scenario, the foundational framework rests upon S&P Global's Green Rules Scenario, but with the addition of assumptions discussed below.

The Max Electron scenario assumes an unprecedented rate of electrification across various modes of transportation. This scenario relies on the widespread adoption of electric vehicles (LDV and HDV), transforming the landscape of personal and commercial transportation and considers electrification possibilities in aviation and the marine sectors. The Max Electron Scenario represents a comprehensive and innovative approach to reducing carbon emissions, fostering clean energy solutions, and ushering in a new era of electrified mobility.

The Max Electron Scenario is aligned with the EU's net zero goals and either meets or exceeds the sub targets set in Fit for 55, RefuelEU Aviation and FuelEU Maritime.

Total Energy Demand

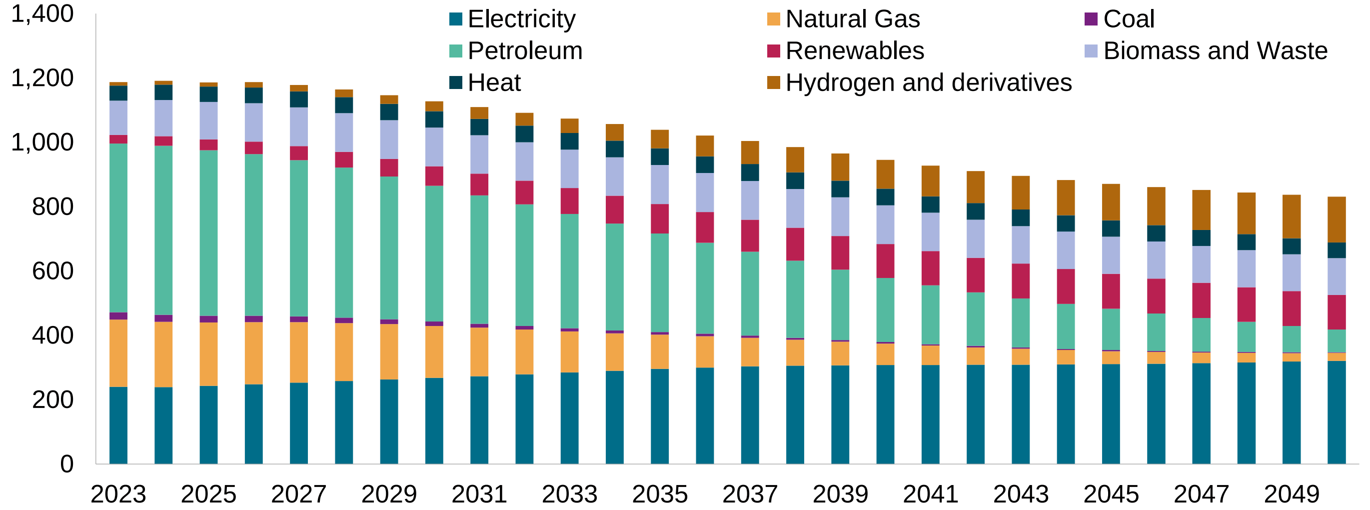
Total energy demand includes below sub-sectors:

- Transport sector
- Industrial sector
- Agriculture sector
- Residential heating sector
- Commercial heating sector
- Feedstock

The outcome of the total energy demand in Max Electron scenario highlights the overall decline in total energy demand due to massive electrification and efficiency gains in different sub sectors as compared to current level. Overall share of petroleum in total energy demand shrinks to only 8.5% by 2050 in Max Electron scenario. For decarbonization and achieving a net-zero future, electricity emerges as a cornerstone solution due to its potential for renewable integration and reduced environmental impact in Max Electron case. By 2050, electricity gains 39% of total energy demand in all sub sectors by 2050. Renewable demand i.e., small-scale nonelectric renewables (e.g., solar thermal water heating, heat pumps), mostly came from residential and commercial heating along with part of industrial and agriculture sector, increases its overall share to 13% by 2050, displacing the traditional hydrocarbon energy sources for heating in overall energy demand.

Majority of hydrogen and derivatives demand came from Transport and industrial sector, where hydrogen from electrolysis is considered an important source to decarbonize overall energy mix in both scenarios. Overall hydrogen and derivatives and bio mass (includes bio-fuels and traditional bio mass) have 31% of total energy demand by 2050.

Total energy demand outlook - Max Electron scenario - excludes Transformation Energy (MMtoe)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

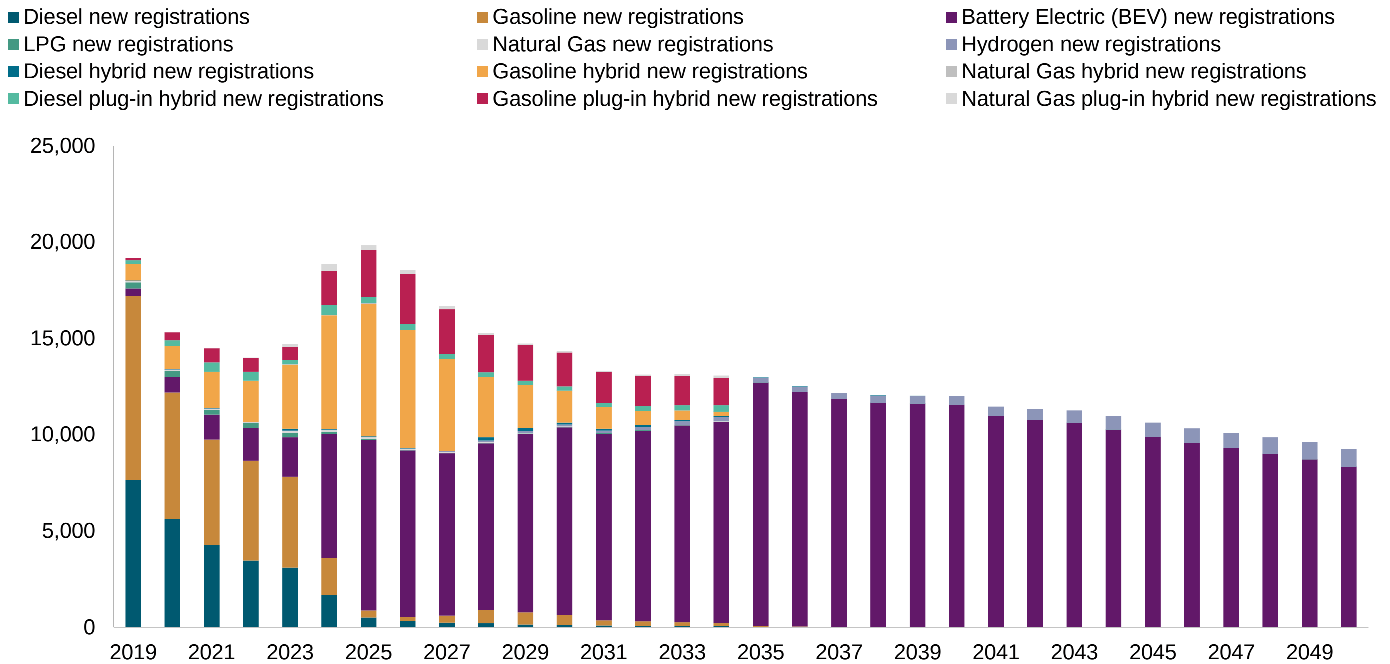
Road transport

One of the key differences in Max Electron and More Molecule scenarios are the evolution of % sales of BEV and ICE engines with time.

For LDVs (passenger and LCV), there is a post-2035 internal combustion engine ban for new sales of LDV (passenger and LCV) in the road transportation sector for the Max Electron scenario. All these sales are moved to Battery Electric Vehicles to maintain the vehicle population with resultant reduction in liquid fuels demand and increase in electricity demand in the Max Electron scenario.

Note: this study was started in late 2023, hence 2022 is actual data, 2023 vehicle sales onwards are estimates/forecasts under the scenarios. With known actual sales of hybrids/EV's for 2023 and 2024 below the scenario forecasts this further emphasizes the scale of the challenge of reaching net zero by 2050.

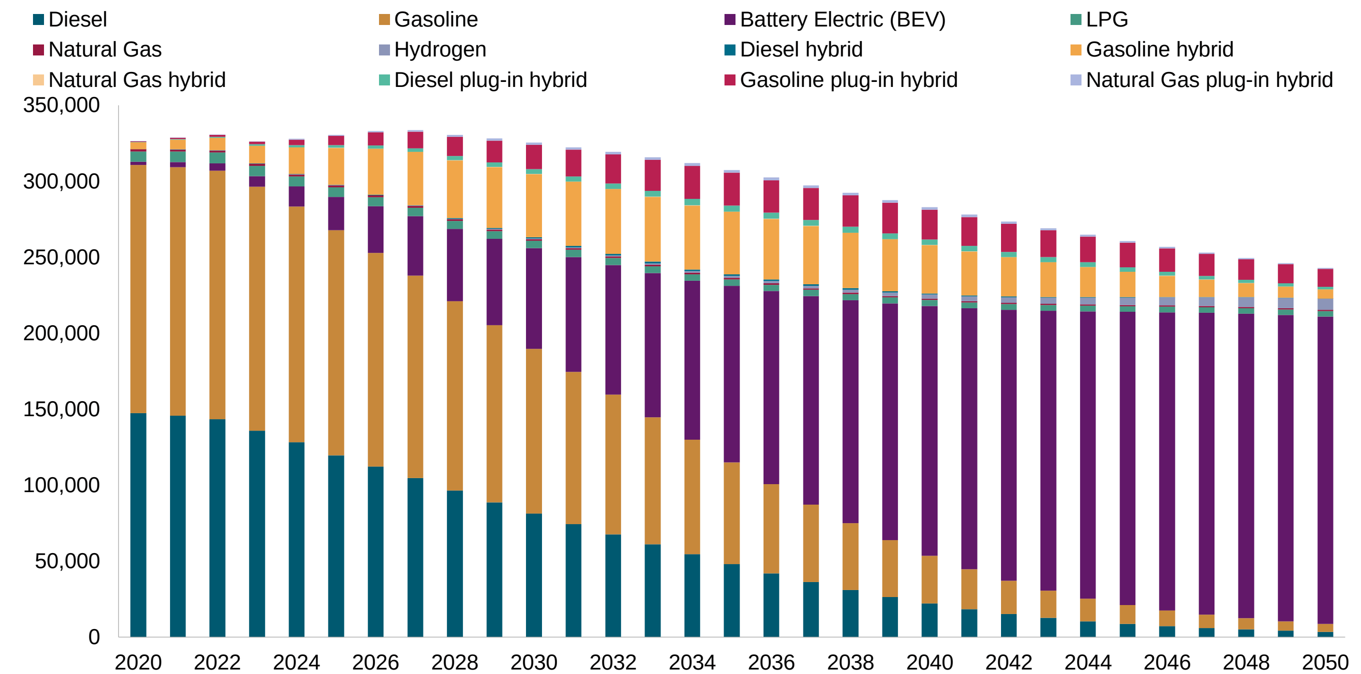
Max Electron LDV new registrations (thousands of vehicles)



Source: S&P Global Commodity Insights.

The post-2035 ban of ICE engine in Max Electron scenario results into overall change in the LDV split by power train. In Max Electron scenario BEV grows to 83% of the overall LDV fleet by 2050 in EU+ region.

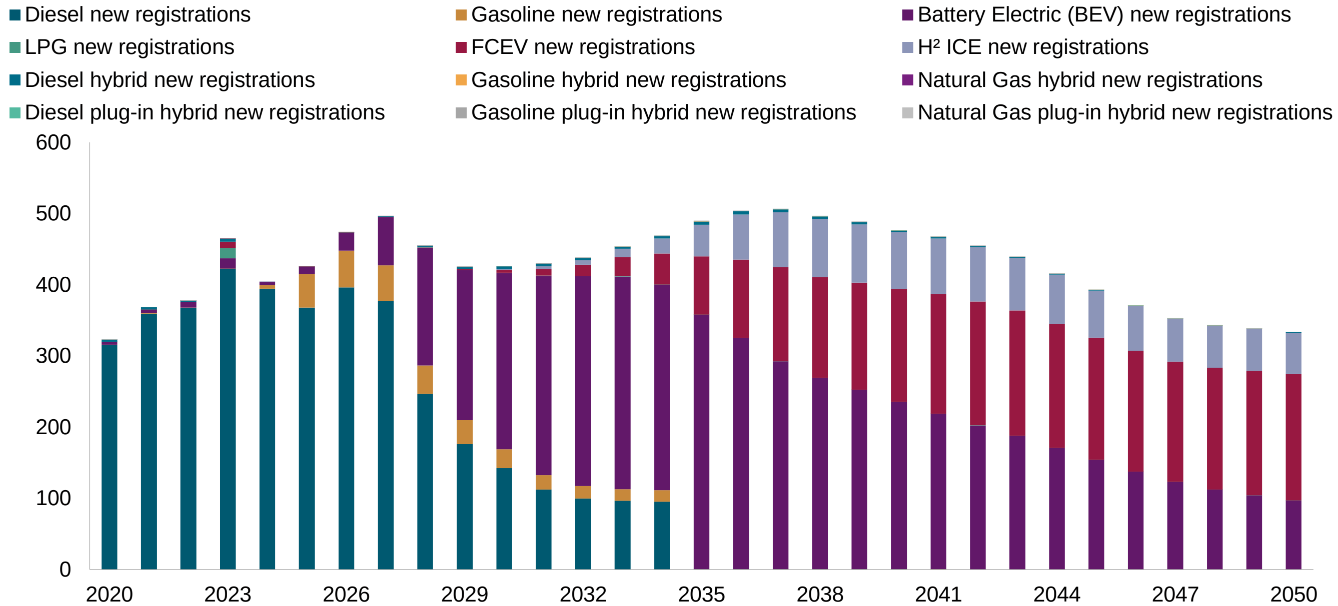
Max Electron Road Transportation Indicator- LDV Fleet Split by Power Train (thousands of vehicles)



Source: S&P Global Commodity Insights.

For HDV (Heavy Duty Vehicle) in Max Electron, there is a ban on new sales of diesel and gasoline engine post 2035 for the HDV section of road transportation sector. The scenario also sees stronger penetration of battery and hydrogen fuel-cell trucks in HDV sector demand after 2035. Strong increase in number of new registrations in mid 2020s following on from very low numbers in 2020-2022 after the Covid pandemic.

Max Electron: new HDV registration split by powertrain (thousand vehicles)



Source: S&P Global Commodity Insights.
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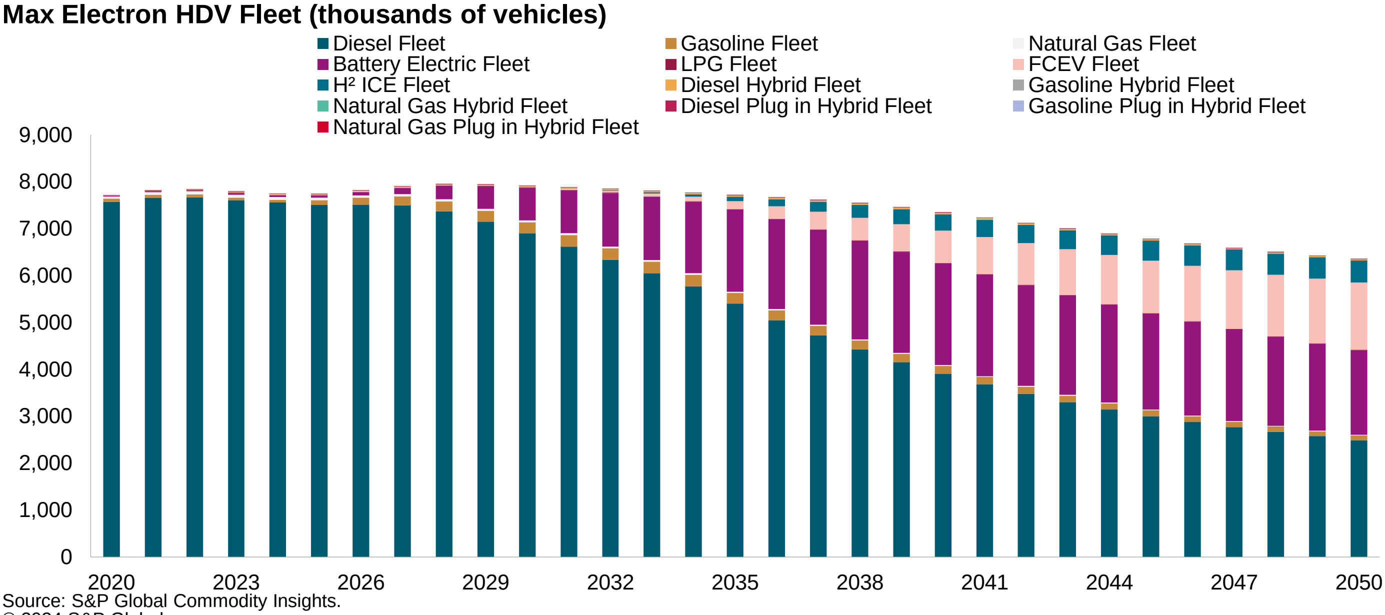
Post 2035, the ban on diesel and gasoline engine in Max Electron brings overall change in the HDV split by power train. In Max Electron, diesel and gasoline HDV vehicles reduce to 40% of overall HDV fleet by 2050.

Max Electron HDV Fleet (thousands of vehicles)



Source: S&P Global Commodity Insights.
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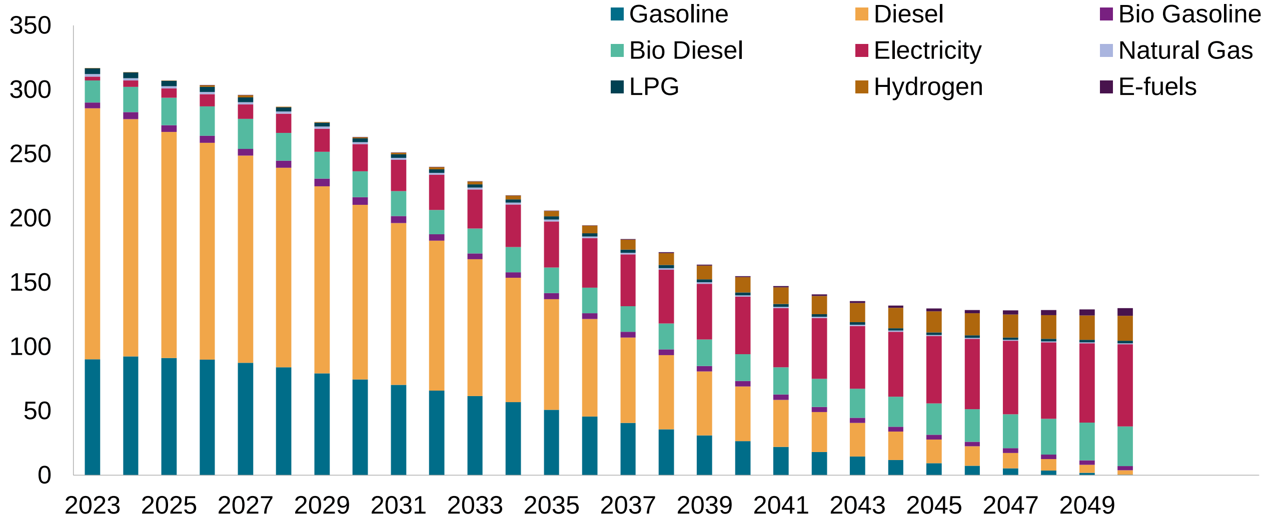
In Max Electron Scenario, the overall impact of ban on new ICE engine sales post 2035 changes the overall road transport fuel mix. Electricity will take over half of the total energy demand in road transport in 2050 and the rest of the fuel mix will be Biofuels, E-fuels and Hydrogen (Fuel cells and H2 ICE).

Fuel Mix for Road Transport - Max Electron (MMtoe)

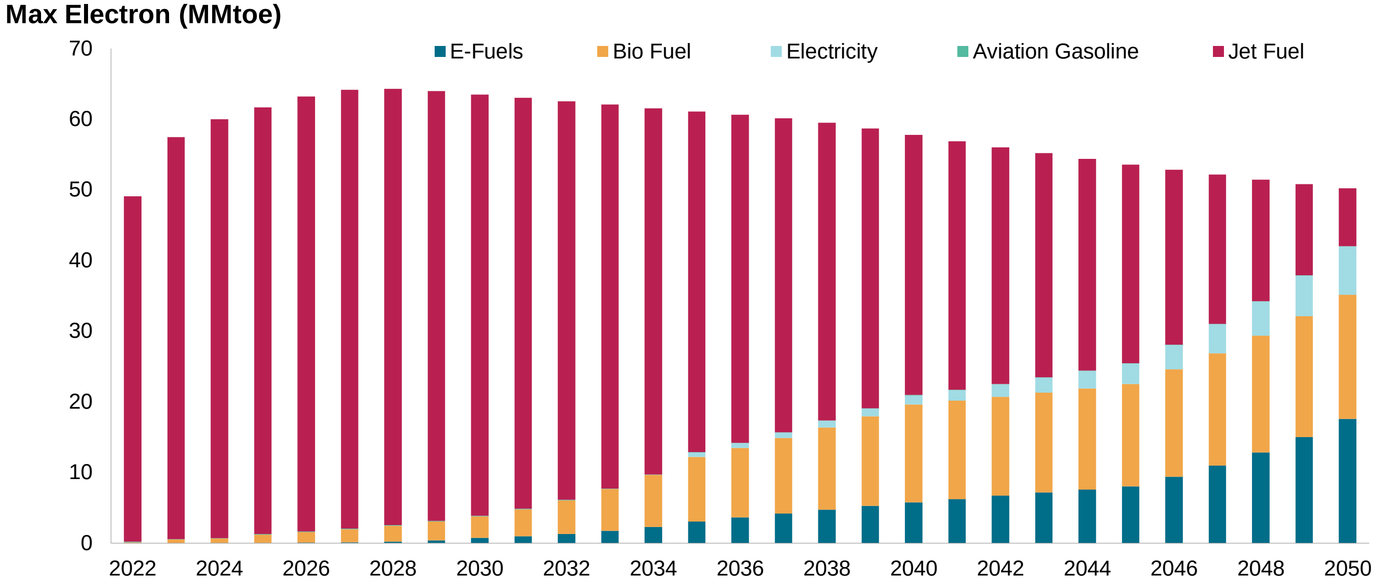


Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Aviation transport

In the Max Electron scenario for the aviation sector, the cornerstone lies in the targets outlined by initiatives such as ReFuelEU Aviation. These targets set the trajectory for a future for advanced Sustainable Aviation Fuel (SAF), which is pivotal in reducing the aviation industry's carbon footprint. Introduction of more ambitious SAF blending obligation, abolishment of jet fuel tax exemption, and unwinding of all free allowances under the EU Emissions Trading Scheme should raise airfares substantially. Meanwhile, a strong policy push to incentivize a switch from air-to-rail for domestic and short-haul travel reduces jet demand, with Green Rules anticipating a more than 130% increase in European rail transport energy consumption by 2050.

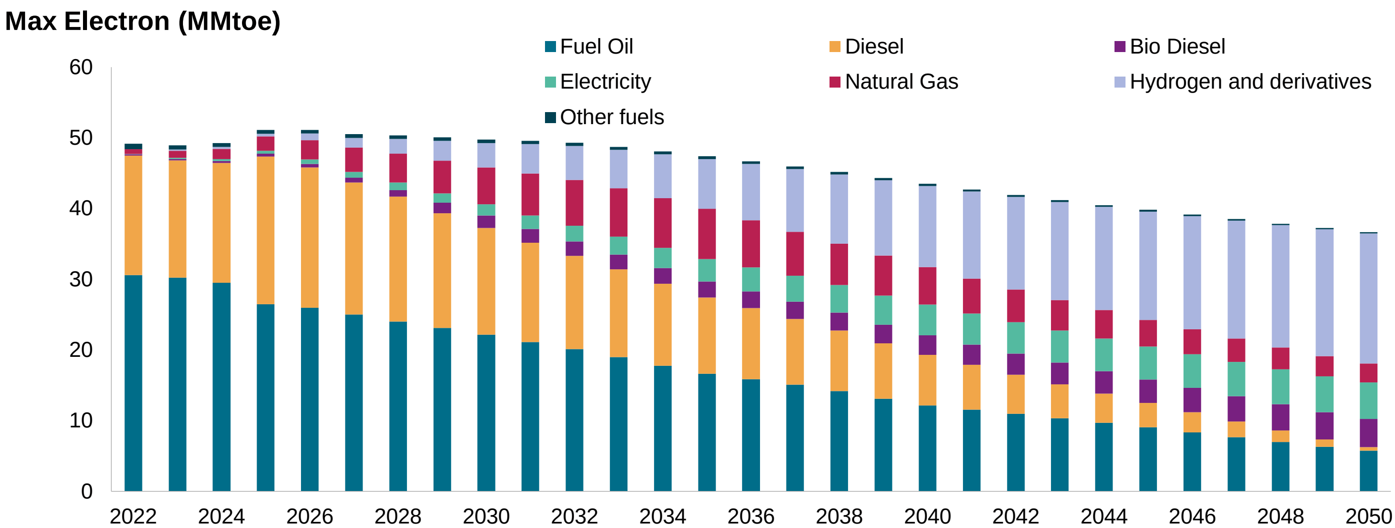
In the Max Electron scenario in the aviation sector, a notable aspect is the assumption of modest electricity penetration for small, short-haul commuter aircraft with hybrid possibilities.



Source: S&P Global Commodity Insights.

Maritime Transport

In maritime sector for Max Electron scenario, residual fuel oil demand will reduce by almost 75% by 2050. Stationary (in port) demand will switch to other available cleaner alternatives. The shipping industry enjoys varied fuel alternatives and in the longer term, the industry is poised to become more fuel efficient. While we don't expect global trade levels to drop, fossil fuel demand from the shipping industry will drop significantly giving way to non-traditional fuels such as ammonia, methanol, hydrogen, biodiesel, and battery electric.

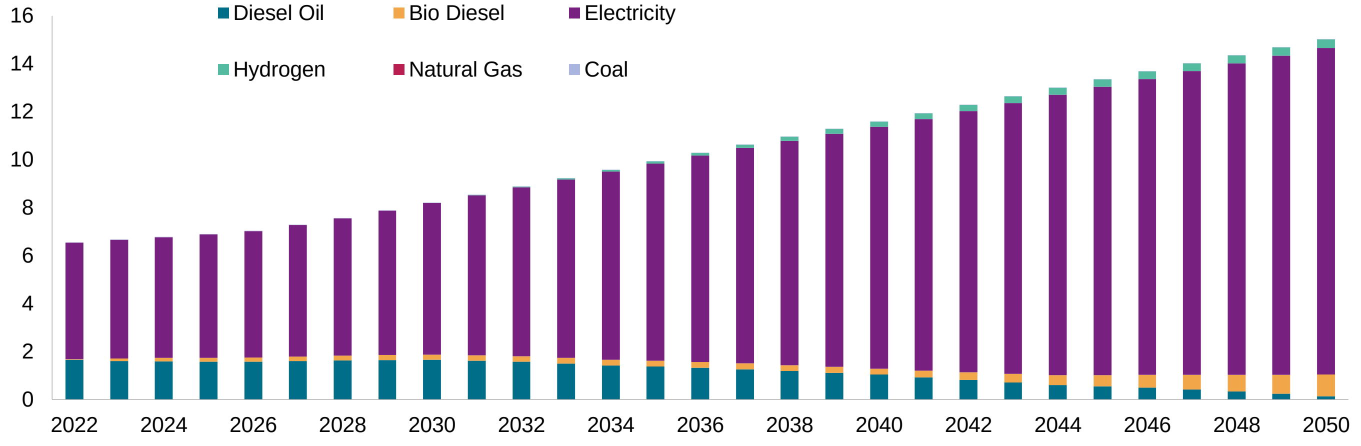


Source: S&P Global Commodity Insights.

Rail Transport

A robust policy drive aimed at encouraging the transition from air to rail for domestic and short-haul travel increases rail energy consumption at the expense of aviation fuel. The Green Rules scenario anticipates a striking shift in European transportation dynamics, projecting a 130% increase in rail transport energy consumption by the year 2050. Notably, over 90% of this escalated energy demand is expected to be met through electricity which with increased renewable electricity generation allows for decarbonization of short-haul travel, marking a pivotal step towards a more sustainable and energy-efficient future.

Max Electron (MMtoe)



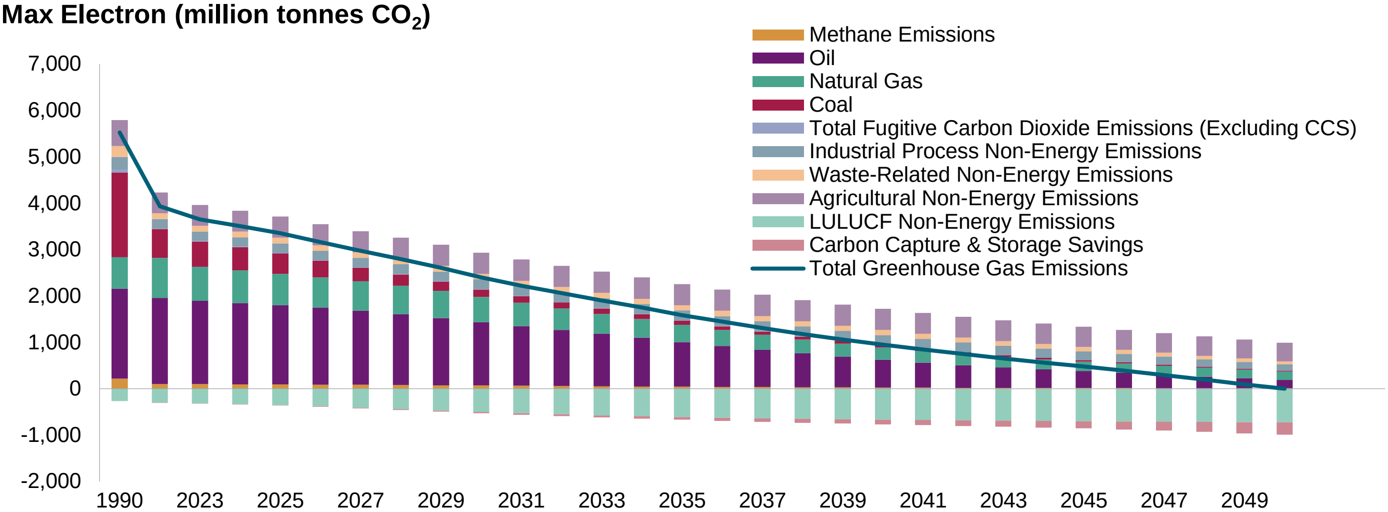
Source: S&P Global Commodity Insights.

Total transport energy reduces in the long term with efficiency gains due to shift towards electric vehicles, efficiency improvement of power trains in different sub transport sectors. Electricity captures ~40% of total energy demand in 2050 for EU+ transport sector.

EU+ Max Electron Scenario Overall Emissions

Overall Emissions in EU+ Max Electron scenario reduces from 5526 million tonnes CO_2 in 1990 to zero in 2050 i.e. a 100% reduction.

Max Electron (million tonnes CO_2)



Source: S&P Global Commodity Insights.

More Molecule Scenario

In the development of the More Molecule scenario, the foundational framework also rests upon the S&P Global Green Rules scenario. The More Molecule scenario is also aligned with the EU's net zero goals and either meets or exceeds the sub targets set in Fit for 55, RefuelEU Aviation and FuelEU Maritime. In More Molecule Scenario, a key assumption underpinning this scenario is that electricity penetration will be lower within the transport sector, as compared to Max Electron Scenario.

The More Molecule Scenario envisions a landscape where the predominant substitution for traditional fuels in these sectors will be through the utilization of green molecules. These green molecules primarily encompass hydrogen and its derivatives such as synthetic fuels, ammonia, e-methanol etc., as well as advanced biofuels. By pivoting towards these innovative and eco-friendly alternatives, the More Molecule Scenario seeks to achieve the EU targets of emissions reduction but with more green molecules, particularly biofuels compared to the Max Electron Scenario.

Total Energy Demand

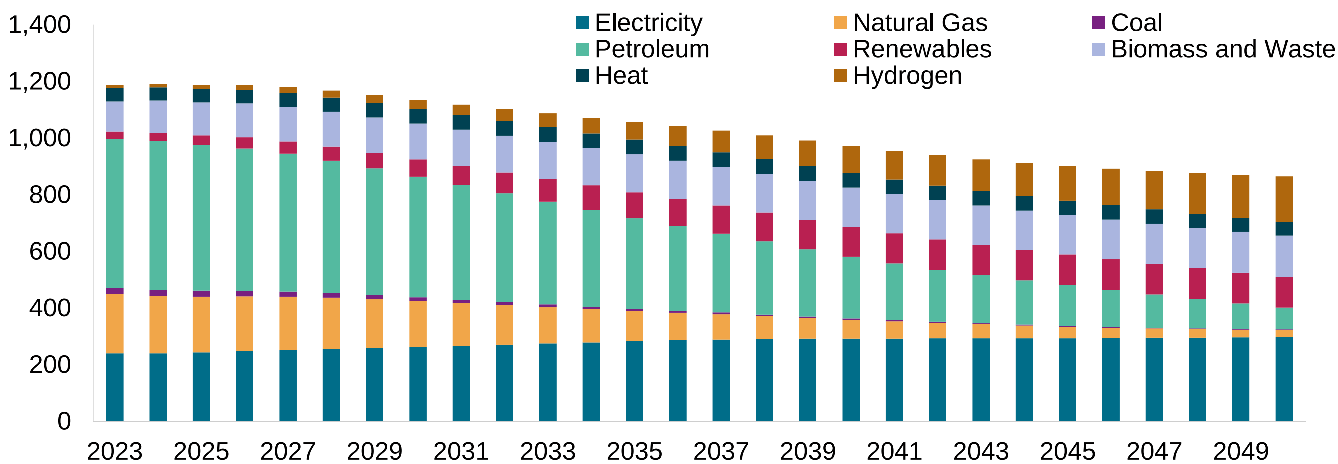
Total energy demand includes below sub-sectors:

- Transport sector
- Industrial sector
- Agriculture sector
- Residential heating sector
- Commercial heating sector
- Feedstock

The outcome of the total energy demand in More Molecule highlights the overall decline in total energy demand with efficiency gains. However overall, More Molecule energy demand is 33 MMtoe higher than Max Electron scenario due to lesser efficiency of molecules as compared to battery electric. Overall share of petroleum in total energy demand shrinks to only 9% by 2050 in Max Electron. For decarbonization and achieving a net-zero future, low carbon fuels are targeted with limited penetration of battery electric in More Molecule scenario. By 2050, electricity gains 34% of total energy demand in all sub sectors by 2050. Renewable demand i.e., small-scale nonelectric renewables (e.g., solar thermal water heating, heat pumps), mostly came from residential and commercial heating along with part of industrial and agriculture sector, increases its overall share to 13% by 2050, displacing the traditional hydrocarbon energy sources for heating in overall energy demand.

Majority of hydrogen and derivatives demand came from Transport and industrial sector, where hydrogen from electrolysis is considered an important source to decarbonize overall energy mix in both scenarios. Overall hydrogen and derivatives and biomass (include biofuels and traditional bio mass) have 36% of total energy demand by 2050 in More Molecule scenario.

Total energy demand outlook under More Molecule scenario, excluding transformation (MMtoe)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.
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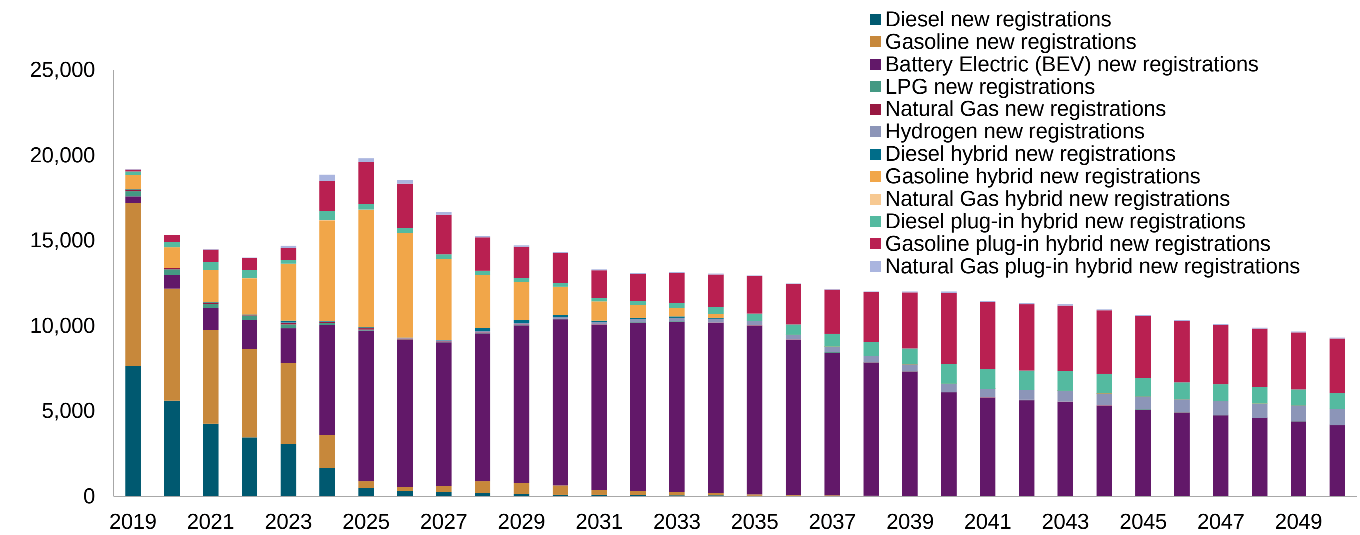
Road Transport

One of the key assumptions change in More Molecule scenario from Max Electron scenario is the inclusion of PHEV (plug in hybrid electric vehicles) sales post 2035 for the passenger and LCV (light commercial vehicle) road transportation sector. Continued sales of PHEVs reach 45% of new vehicle sales by 2040 onwards, in More Molecule scenario. Leading up to 2030 the initial very high rates of electrification are required to meet ETS II requirements in 2030.

More Molecule: new LDV registration split by powertrain (thousands of vehicles)



Source: S&P Global Commodity Insights.
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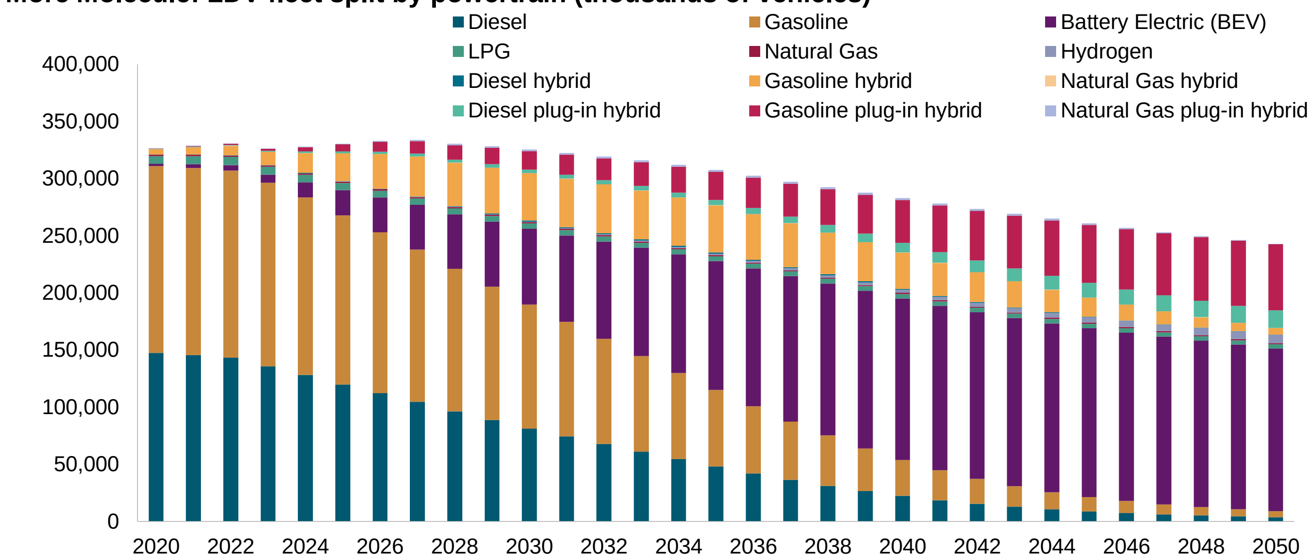
Inclusion of PHEV sales post 2035 in LDV fleet, increases the overall PHEVs share to 20% by 2050 as compared to only 6% in the Max Electron scenario LDV fleet. The overall BEVs share reduced to 68% in the LDV fleet for More Molecule scenario as compared to Max Electron BEVs share of 83%.

More Molecule: LDV fleet split by powertrain (thousands of vehicles)



Source: S&P Global Commodity Insights.
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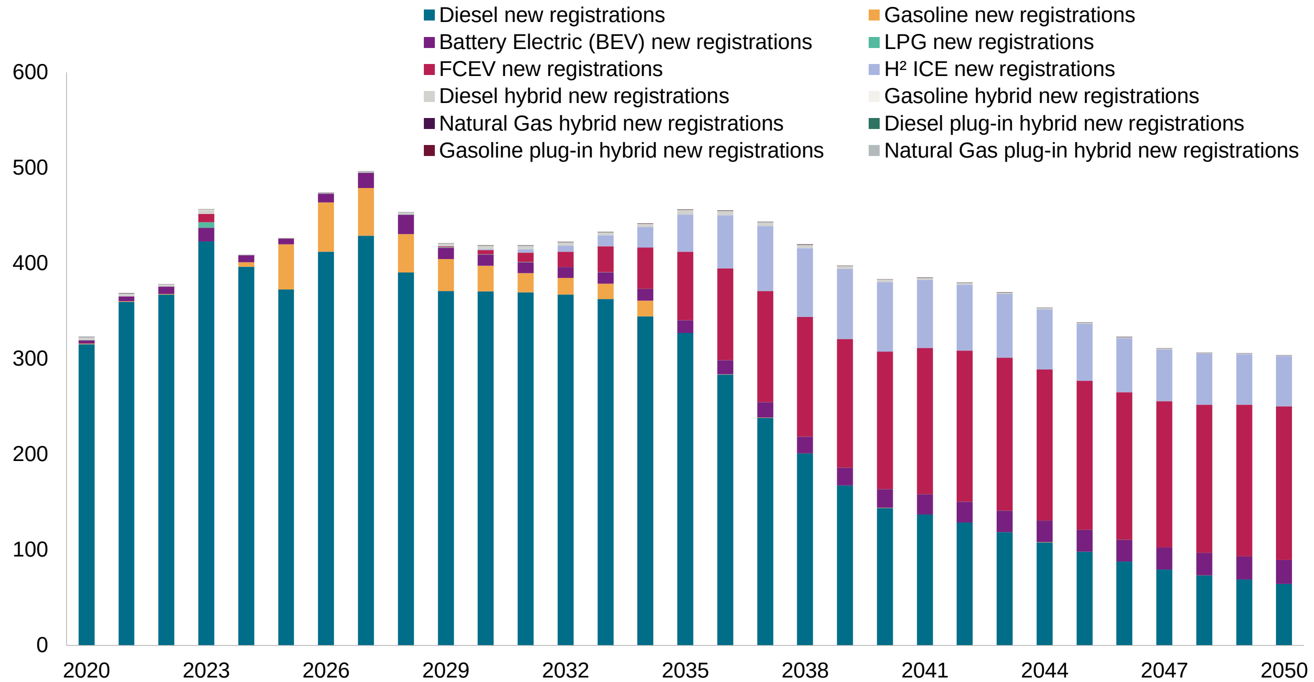
Note: this study was started in late 2023, hence 2022 is actual data, 2023 vehicle sales onwards are estimates/forecasts under the scenarios. With known actual sales of hybrids/EV's for 2023 and 2024 below the scenario forecasts this further emphasizes the scale of the challenge of reaching net zero by 2050.

In contrast to Max Electron, More Molecule diverges in its assumption regarding electricity penetration in Heavy-Duty Vehicles (HDV). More Molecule has a lower degree of electricity penetration in the HDV sector and instead, it places a greater emphasis on the adoption of green molecules, such as advanced biofuels, e-fuels and hydrogen/hydrogen derivatives as the primary means of fuel substitution. In Max Electron, there are no Diesel GV sales post 2035. Strong increase in number of new registrations in mid 2020s following on from very low numbers in 2020-2022 after the Covid pandemic.

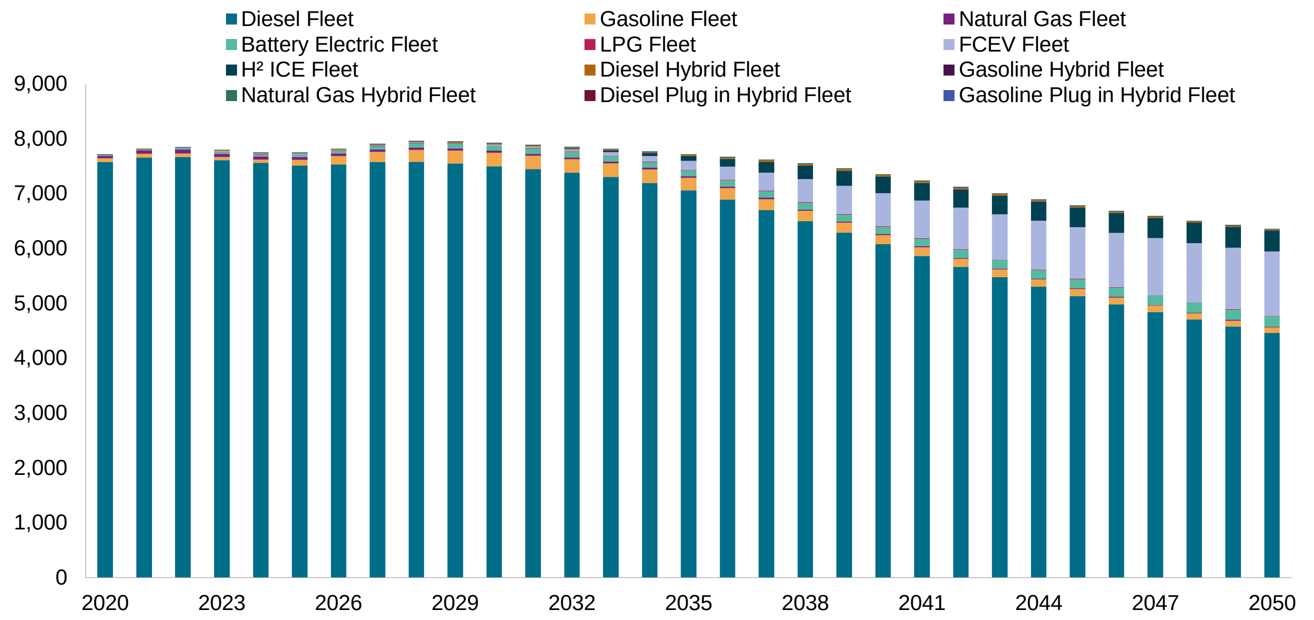
More Molecule: new HGV registrations split by powertrain (thousands of vehicles)



Source: S&P Global Commodity Insights.

BEV penetration in HGV fleet is only 3% of total HGV fleet in More Molecule scenario. In More Molecule, the HGV fleet numbers 2 million more “diesel” vehicles than Max Electron scenarios in 2050. However, the energy demand of these “diesel” power trains is meet by biofuels and e-fuels in long term.

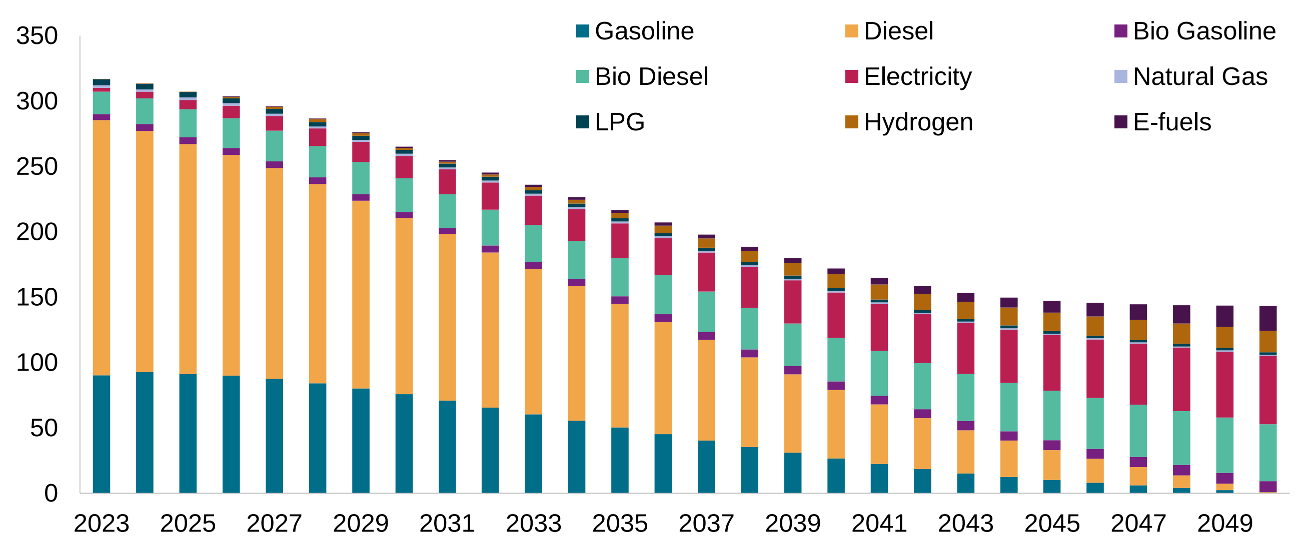
More Molecule: HGV fleet split by powertrain (thousands of vehicles)



Source: S&P Global Commodity Insights.

In More Molecule, the continued ICE engine sales post 2035 changes the overall road transport fuel mix. Electricity share is reduced to only 36% of total energy demand in road transport by 2050 as compared to ~52% in Max Electron. For the remainder, the majority of the fuel mix demand will be occupied by biofuels, e-fuels and hydrogen (fuel cells and H_2 ICE) in 2050. More Molecule results in 19 MMtoe net increase in energy demand compared to the Max Electron, made up of 12 MMtoe less of electricity, and 31 MMtoe of bio-fuels and RFNBO's.

Fuel mix for road transport in More Molecule (MMtoe)

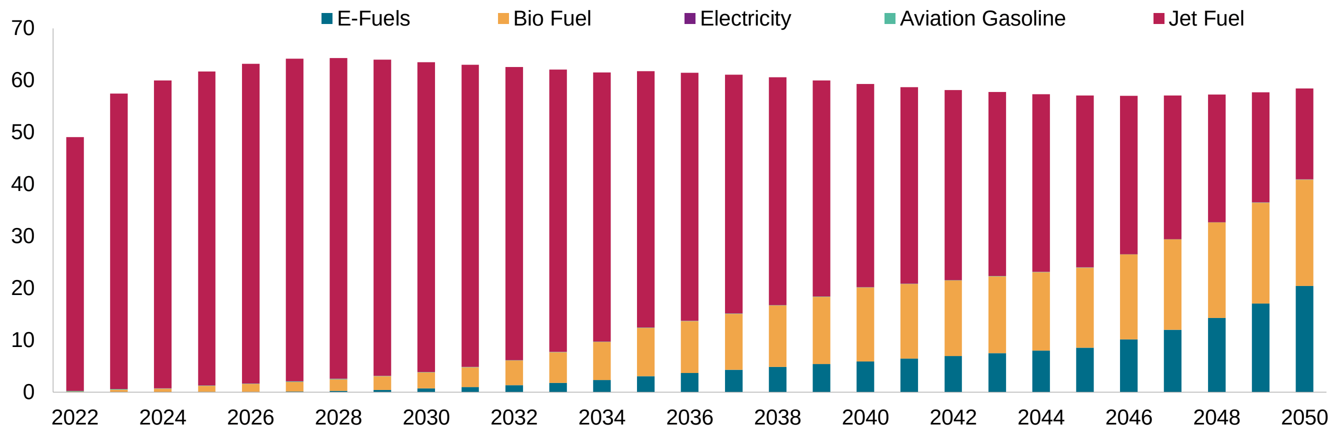


Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

Aviation Transport

The More Molecule Scenario aligns closely with the fundamental principles of Green Rules and Max Electron Scenarios. It relies on the same core assumptions to predict the demand for an energy mix in aviation. However, a notable deviation from the Max Electron lies in a distinctive assumption — the absence of electricity penetration in the aviation sector. Unlike scenarios envisioning widespread electrification, More Molecule envisions the decarbonization of this hard-to-abate sector using advanced bio SAF (Sustainable Aviation Fuel) and e-SAF.

More Molecule aviation transport energy demand by fuel type (MMtoe)

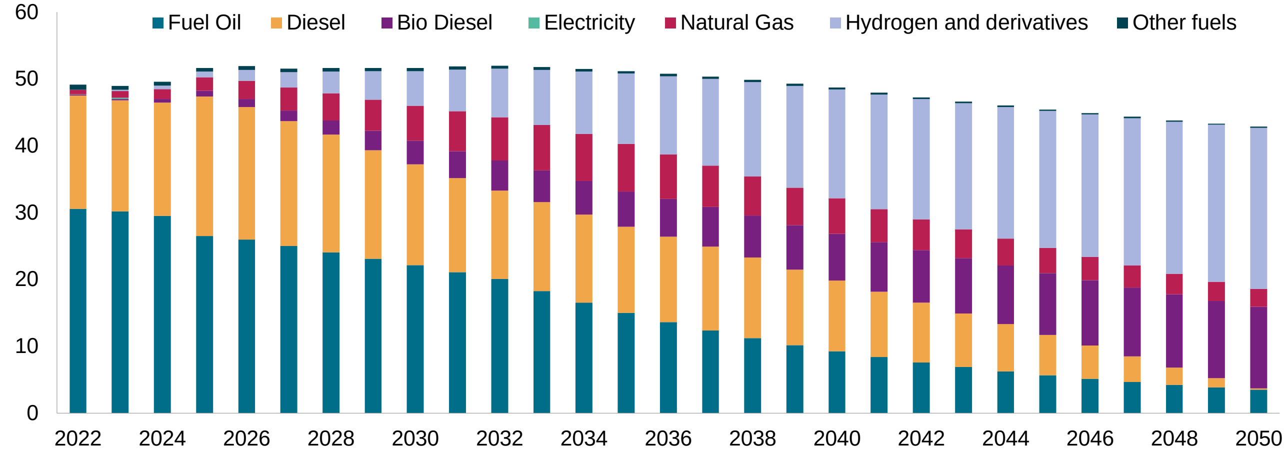


Source: S&P Global Commodity Insights.

Maritime Transport

More Molecule uses same core principles to project the demand for energy in maritime operations. Nevertheless, a notable divergence from Max Electron is a distinct assumption: the exclusion of widespread electricity integration within the maritime sector. In More Molecule, this hard-to-abate sector is envisaged to undergo decarbonization through a different route, specifically with the utilization of hydrogen derivatives i.e. ammonia, e-methanol etc.

More Molecule maritime transportion energy demand by fuel type (MMtoe)



Source: S&P Global Commodity Insights.
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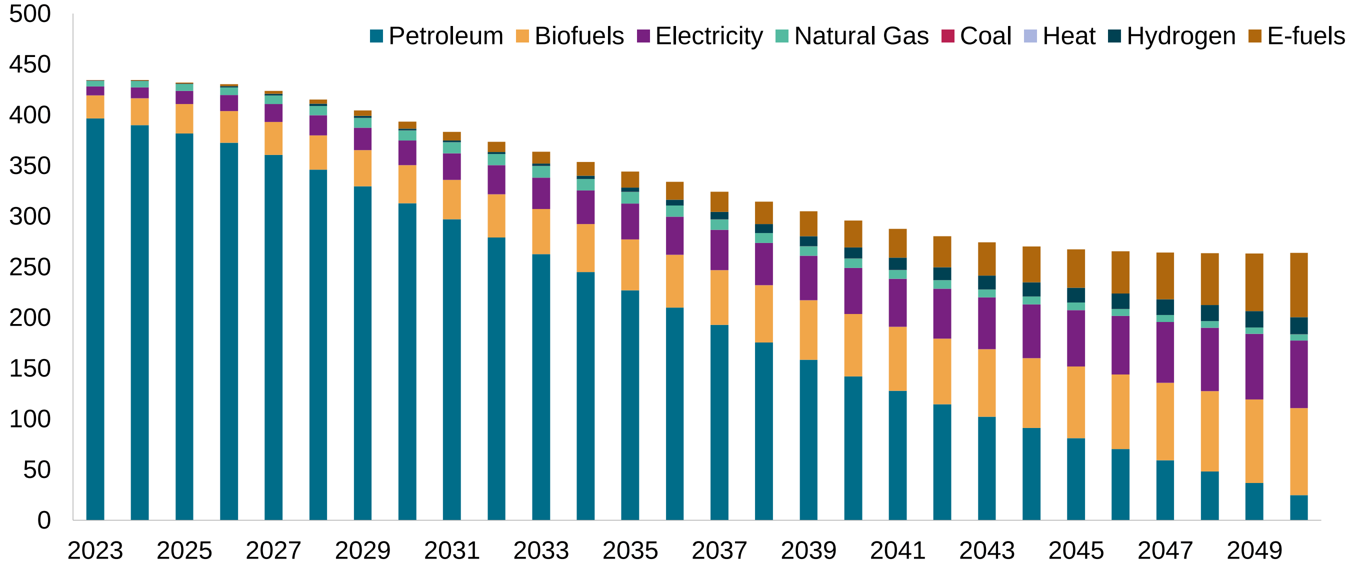
In More Molecule, total transport fuel mix have 57% share of biofuels and E-fuels in 2050 as compared to only share of 38% in Max Electron. In both scenarios, the petroleum energy share is less than 10% of final energy mix in the transport sector in 2050.

Fuel Mix for total transport - More Molecule (MMtoe)



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.
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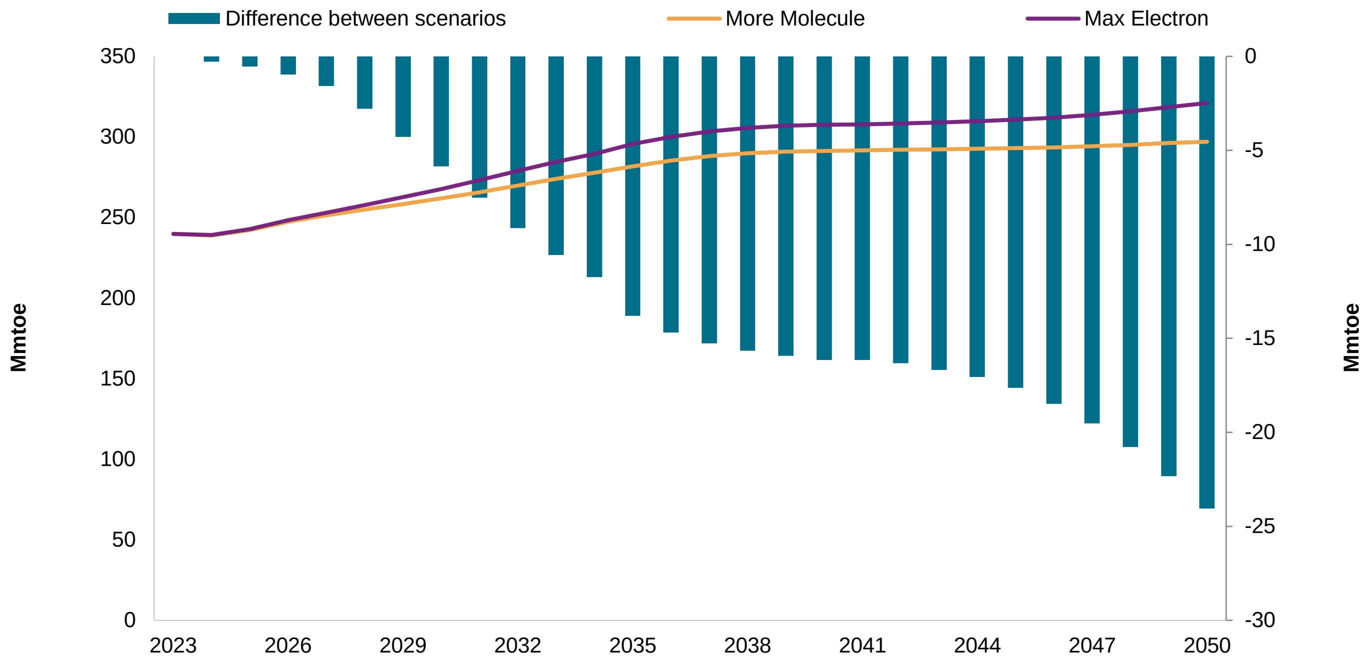
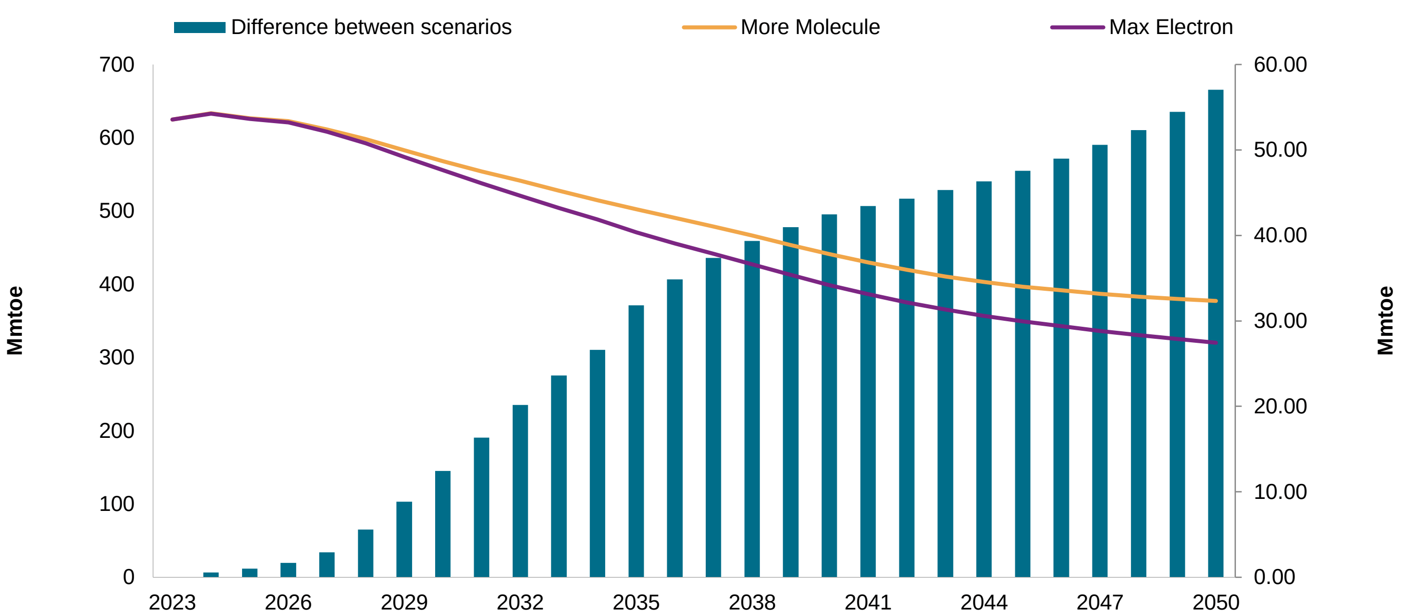
Comparing the total final energy demand for More Molecule and Max Electron scenario by 2050, Max Electron will have 24 MMtoe of more battery electric consumption as compared to More Molecule scenario. The More Molecule scenario has 57 MMtoe more molecular fuel as compared to Max Electron scenario by 2050.

Electricity demand outlook - Scenarios comparison



Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom. Excludes Transformation demand.
Source: S&P Global Commodity Insights.

Petroleum, Bio-fuels, Hydrogen and derivatives demand outlook - Scenarios comparison

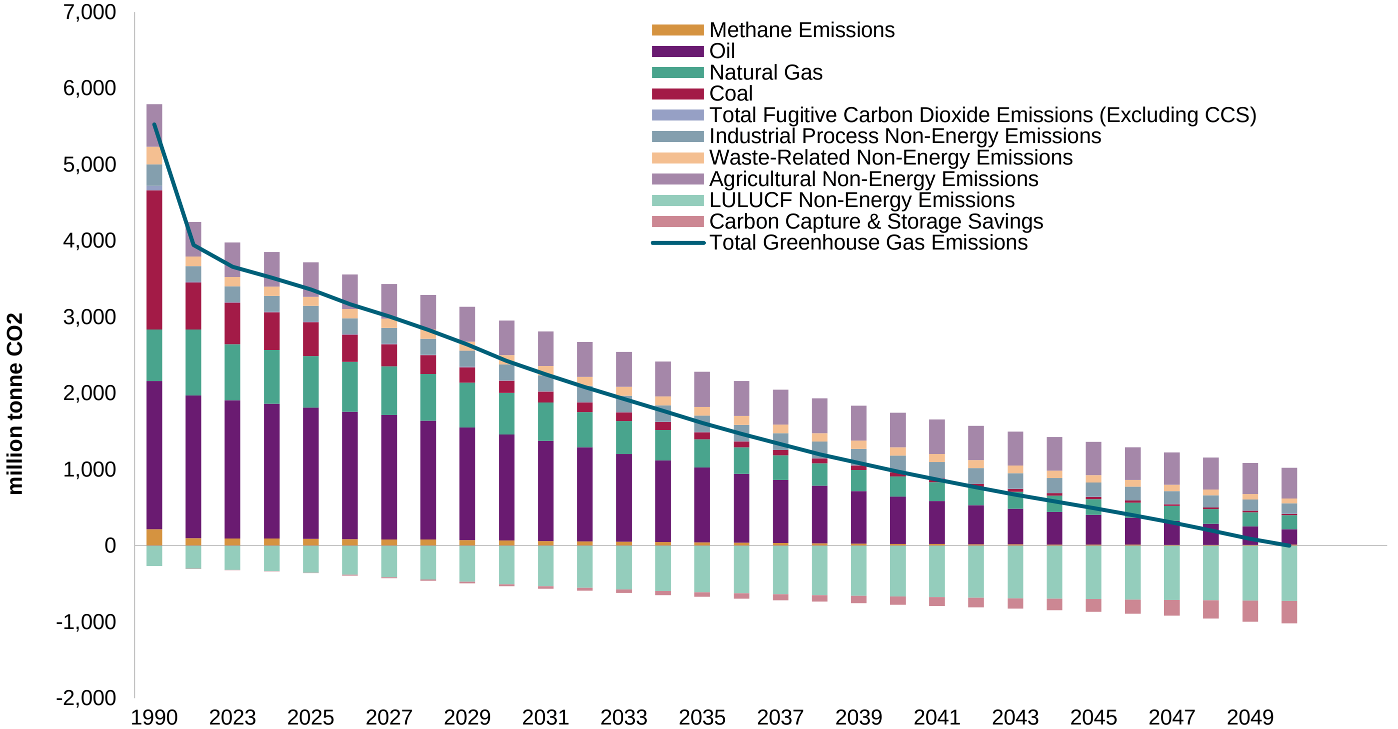


Note: For the EU 27 countries, Norway, Switzerland and the United Kingdom
Source: S&P Global Commodity Insights.

EU+ More Molecule Scenario Overall Emissions

Overall Emissions in EU+ More Molecule reduces from 5526 million tonnes CO_2 in 1990 to zero in 2050, a 100% reduction.

Total GHG emissions in More Molecule (million tonnes CO_2)



Source: S&P Global Commodity Insights.

Glossary Table

CCR	Continuous Catalytic Reforming
CCS	Carbon Capture and Storage
CDU	Crude Distillation Unit
CIF	Cost, Insurance Freight
CWT	Complexity-Weighted Ton
ETBE	Ethyl Tertiary Butyl Ether
ETS	Emissions Trading Scheme
EU+	European Union (27 countries) + Norway, United Kingdom, and Switzerland
EV	Electric Vehicles
FCC	Fluid Catalytic Cracking
FOB	Free On Board
GHG	Greenhouse gas
GRM	Gross refining margin
HDV	Heavy-Duty Vehicles (HDV)
HMU	Hydrogen Manufacturing Unit
HSFO	High Sulphur Fuel Oil
ICE	Internal combustion engine
IEA	International Energy Agency
KBPD	Thousand Barrels Per Day
LDV	Light-Duty Vehicles
LP	Linear Programming
LPG	Liquified Petroleum gas
LSFO	Low Sulphur Fuel Oil
MED	Mediterranean region
MMTPA	Million metric tons per annum
MTBE	Methyl Tertiary Butyl Ether
N+2A	Naphthene and Aromatic
NGL	Natural gas liquids
NWE	Northwest Europe
PIMS	Process Industry Modelling System
RFCC	Residue Fluid Catalytic Cracking
RFNBO	Renewable fuel of non-biological origin
SAF	Sustainable Aviation Fuel
SDA	Solvent De-asphalting
SMR	Steam Methane Reforming
SR Diesel	Straight Run Diesel
US	United States
VGO	Vacuum Gas Oil

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