ENSURING RESILIENCE IN THE EUROPEAN ENERGY TRANSITION

STRATEGIC USE OF GASES TO MEET EU CLIMATE AMBITIONS

Technical Report

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Contents

Overview

This document provides a description of technical details and assumptions of our analysis underlying the report “Ensuring Resilience in the European Energy Transition – Strategic Use of Gases to Meet EU Climate Ambitions” on behalf of Eurogas.

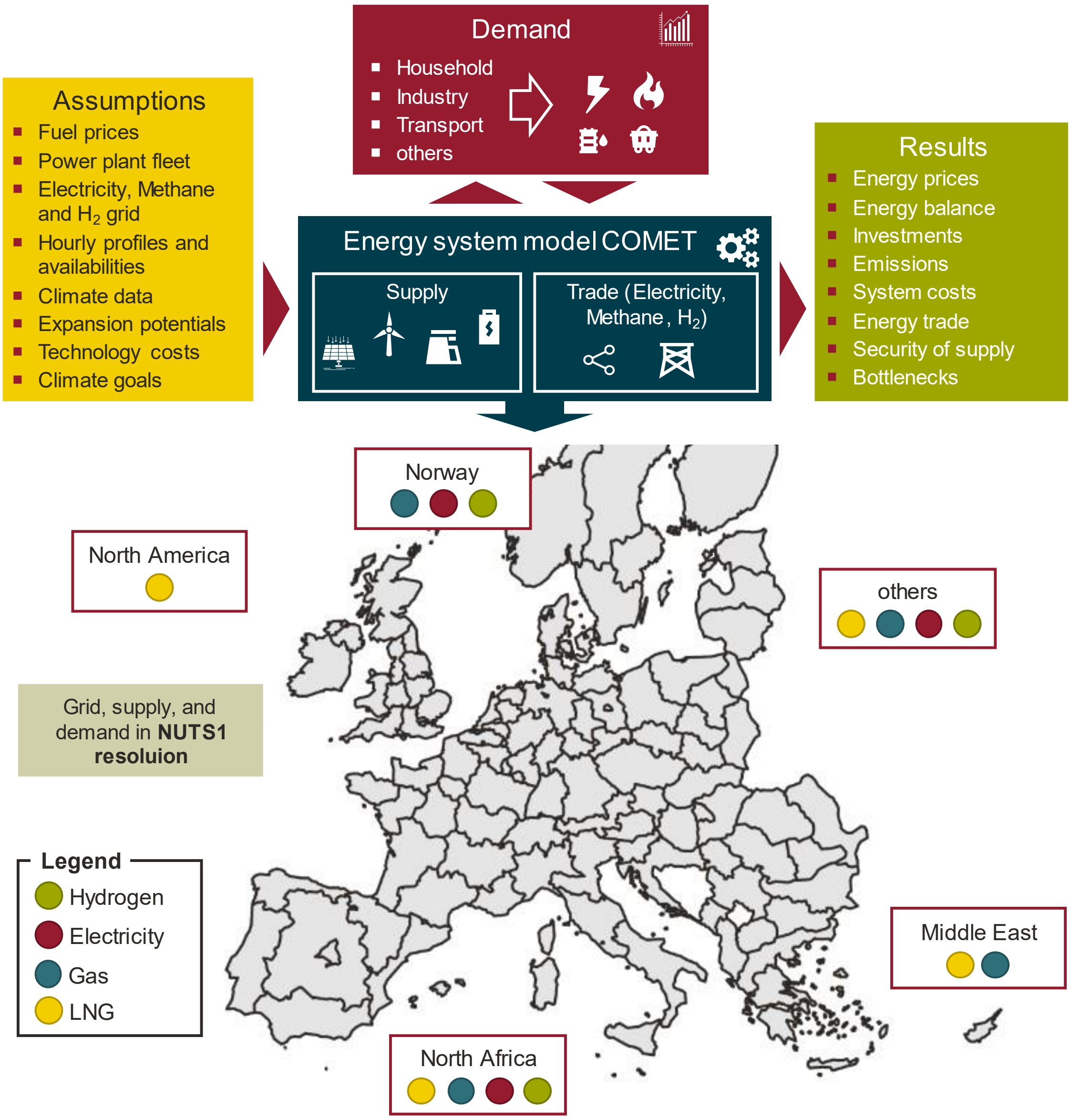
The technical report is structured as follows:

- Annex A – Model description of Frontier’s energy system model COMET
- Annex B – COMET input assumptions
- Annex C – Final energy demand modelling
- Annex D – System cost comparison
- Annex E – Licence notices

Annex A – Frontier's energy system model COMET

For this study, we use Frontier's energy system model COMET. The model simulates the future development of European energy markets by optimising investment and dispatch of various energy conversion and storage technologies, as well as trade within and beyond the modelled region (currently EU27, EFTA, and the UK). Its objective is to minimise total costs of serving Europe's final energy demand for electricity, methane, hydrogen, liquids, heat, and other energy, taking into account technical, political, and economic constraints (see Figure 1).[1]

Figure 1 COMET overview

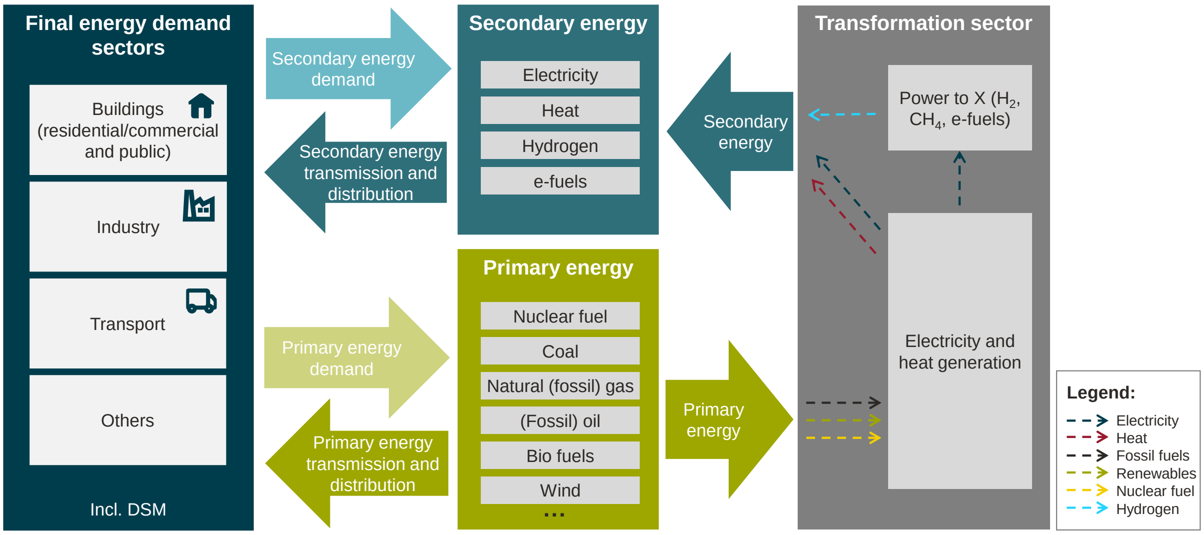


Source: Frontier Economics

1 The model minimises the total actual/economic system costs. Thus taxes, tariffs and subsidies are neglected.

The model choses the cost-optimal mix of supply options to serve demand. For example, for serving methane demand, the model can chose between importing LNG via ship or natural gas via pipeline, invest in facilities to produce biomethane from biomass or use electricity to produce synthetic methane. Using aggregated representations of European transmission networks and import ports, we endogenously optimise trade flows between region within the model and outside the model, which allows us to identify potential trade bottlenecks. Figure 2 illustrates the energy flows between the final demand sector and the energy conversion sector.

Figure 2 COMET energy conversion overview



Source: Frontier Economics

Due to the high spatial granularity and the explicit modelling of transmission and transport constraints for individual energy carriers, COMET is able to provide insight into infrastructure constraints, in particular for the integration of variable renewable energies in the European energy system.

For electricity, a simplified representation of the European electricity transmission grid is used. Based on detailed line and grid data from ENTSO-E and other publicly available sources, we use a grid reduction approach to reduce the underlying detailed physical grid data to match the regions used in the model. This enables us to the deduce conclusions regarding the stress on the transmission grid, potential bottlenecks and the order of magnitude of required grid extensions in certain scenarios.

COMET generally uses the 92 EU NUTS-1 regions[2] plus further regions outside the EU (while deviating from this where necessary, for example due to the grid infrastructure or the market set-up). As representative years, we include 2025, 2030, 2040, 2050, while focusing our analysis on the years 2030, 2040 and 2050.

2 See EuroStat NUTS Maps: https://ec.europa.eu/eurostat/web/nuts/nuts-maps.

We model hourly energy consumption and supply for typical weeks selected to closely approximate a full year. Additionally to modelling these typical weeks, COMET ensures resource adequacy by considering a cold dark doldrums period (*kalte Dunkelflaute*) that was selected based on the analysis of more than 40 years of historical weather data. This period of exceptionally cold temperatures, little solar radiation and low winds speeds results in a period of exceptionally high residual demand (final demand minus the generation of variable renewable energies) – which the model has to make sure to be able to supply.

The final energy demand is an exogenous input for the model. To determine national final demand, we align with the methodology used in the TYNDP 2024, i.e., deploy the *Energy Transition Model*[3]. The model includes six final demand sectors which are further broken down into 30 subsectors and demand types.

In the following sections, we present certain model features in greater detail.

A.1 Main input

- **Final demand:** The final energy demand is an exogenous input for COMET. Flexible demand (e.g. smart charging of EVs or shifts of electric heating) is optimised endogenously according to technical restrictions.

- **Existing capacities:** The model uses a brownfield approach, thus all existing assets are taken into account, including power plants, storages, grid infrastructure, electrolysers, etc. Existing capacities are retired either exogenously (if known decommissioning dates are reached), or endogenously if their deployment is no longer economical.

- **Fuel and carbon prices:** Fuel prices are provided as exogenous inputs to the model, based on recent global price forecasts from the IEA's World Energy Outlook and supply potentials for different exporters. Due to the explicit modelling of methane and hydrogen markets, including domestic production, prices are affected by the endogenous production and trade optimisation. We model an annual carbon budget according to the EU emission targets, resulting in endogenous CO_2 prices.

- **Technology costs:** Investment and operating costs are based on public sources and our research.

- **Capacity limits for renewables:** We use data published by the EC's Joint Research Centre[4] for potentials in individual model regions and align with country-level trajectories from the TYNDP 2024 Draft Supply Input.

3 https://energytransitionmodel.com/about

4 https://data.jrc.ec.europa.eu/collection/id-00138

- **Market framework and regulation:** Current market framework and regulations – for example concerning the use of nuclear plants, coal phase-outs or technology support schemes – are taken into account.

A.2 Main output

- **Energy balance:** Full energy balances by energy carrier and sector, including imports and exports as well as consumption and supply.

- **Emissions:** Full CO_2 balances by region.

- **Energy prices:** Marginal costs of each endogenously produced energy carrier (electricity, hydrogen and e-fuels).

- **Investments and dispatch:** Capacity additions by technology and fuel as well as (annual) production and generation values.

- **System costs:** Costs for all endogenous investments, energy supply and carbon capture.

A.3 Regional granularity

The energy system in the past was characterised by a high centralisation of supply capacities and a clear separation of demand and supply. With the accelerating energy transition, this is quickly changing: Decentralised variable renewables, distributed storage, prosumers, and the increasing digitalisation and flexibility of final demand will result in a more heterogenous energy landscape. This renders modelling with high spatial granularity necessary to appropriately capture the increasing regional differences.

COMET is therefore based on the 92 NUTS-1 regions in the European Union, plus further regions outside the EU. To maintain a manageable size of the computing problem, some NUTS-1 regions are aggregated to bidding zones. In total, we model more than 50 bidding zones in Europe and neighbouring regions. For determining electricity grid capacities between the model regions, we use line by line and node by node data for the European transmission grid which is then aggregated to reflect model regions.

While exact locational data is available for certain inputs, others have to be approximated using proxy data. To calculate electric vehicle demand, for example, we use spatial information regarding population and population density to deduct the regional distribution of the total national fleet. To improve clarity, scenario results are aggregate to larger geographical areas.

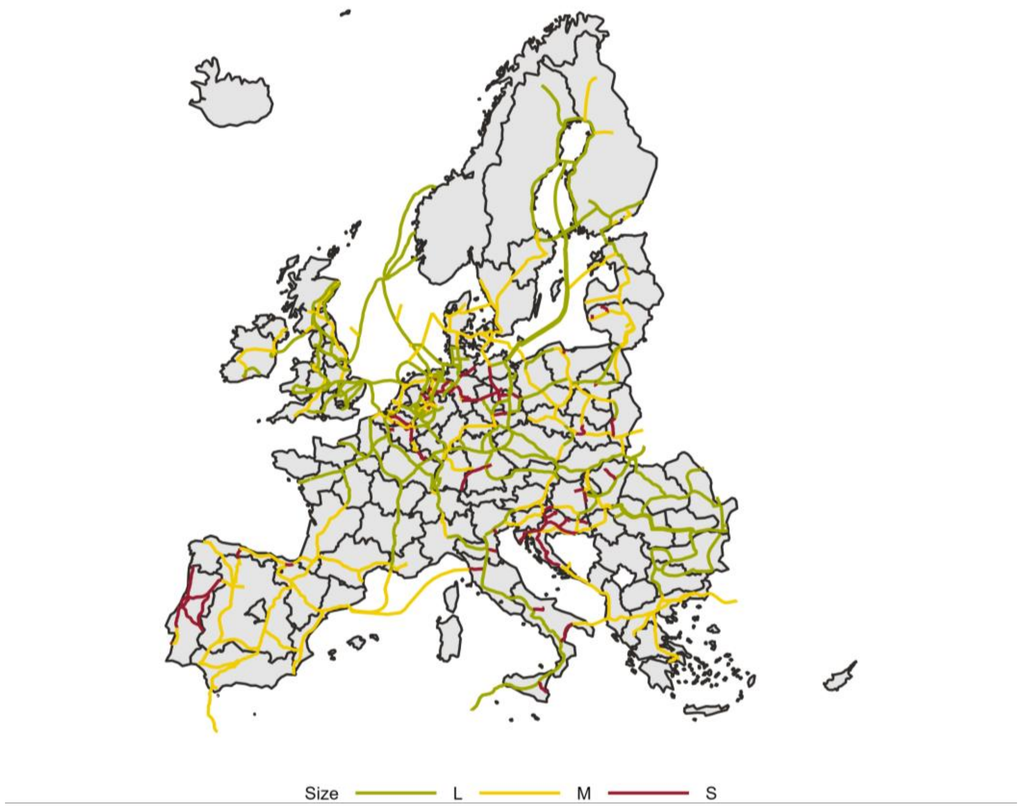
A.4 Grid model and representation in COMET

The co-optimisation of investments, dispatch, storage usage, as well as methane, hydrogen and electricity network usage requires a simplified representation of the European transmission system.

Methane and hydrogen network

COMET considers restrictions for the transmission of methane and hydrogen by approximating net transfer capacities between model regions (see Figure 3 for an illustration of the used hydrogen grid data). Our model incorporates both new builds specifically designed for hydrogen transport and the repurposing of existing methane pipelines for hydrogen use. By focusing on the transportation grid, we implicitly assume that the distribution network has sufficient capacity to handle the requested volumes. Hence our model focuses on the primary channels for large-scale hydrogen and methane movement across Europe.

Figure 3 European Hydrogen Backbone 2040



Source: European Hydrogen Backbone (2023); latest version always here: https://www.ehb.eu

Data sources

COMET's net transfer capacities for methane and hydrogen between model regions are derived in a separate input workflow, based on a number of sources (details below), and by using parts of the grid workflow of the open source European energy system model PyPSA-EUR.

The methane grid is based on SciGRID_gas Europe[5] and reviewed manually based on ENTSO-G's Natural Gas TYNDP 2022. The hydrogen grid is based on the Hydrogen Infrastructure Map and the European Hydrogen Backbone. All sources include geo-spatial information, transfer capacities, storage capacities and connections to countries outside Europe. The import capacities of LNG, biomethane and hydrogen from outside of Europe are obtained from the TYNDP 2024 Draft Supply Inputs.

Calculation of net transfer capacities

The gas and hydrogen network representation is developed as follows:

- **Starting point:** The initial data for the methane and hydrogen grids was sourced from publicly available datasets:
  - Methane grid: raw data was extracted from SciGRID_gas Europe.
  - Hydrogen grid: raw data was obtained from the Hydrogen Infrastructure Map.

  Both sources provide comprehensive information on geographic layout, trading capacities between and within countries, storage facilities, and connections to regions outside Europe.
- **Mapping grid nodes to spatial areas:** Each grid node is mapped to a specific spatial area to facilitate accurate modelling using parts of the PyPSA-EUR grid workflow:
  - A Voronoi cell algorithm is used to associate each grid node with a spatial area, ensuring that these areas remain within NUTS-1 regional borders.
  - This process consolidates pipelines that are geographically close and have the same connections, treating parallel pipelines as a single entity.
- **Methane grid development:** To account for future developments, we integrate expansion plans based on the ENTSO-G's Natural Gas TYNDP 2022, which includes investments in new pipelines and updates to existing infrastructure (Figure 4 illustrates our resulting methane grid in 2050). The update process involved three mapping options:
  - Direct mapping to network nodes from the existing grid.
  - Automatic mapping to the closest node.
  - Adding new nodes where necessary.
  - Manual refinement to ensure accuracy.

5 https://www.gas.scigrid.de/

- **Hydrogen grid development:** Similar to the methane grid, we take into account capacity expansion plans according to the Hydrogen Infrastructure Map and European Hydrogen Backbone (see Figure 5 illustrating our resulting hydrogen grid in 2050).

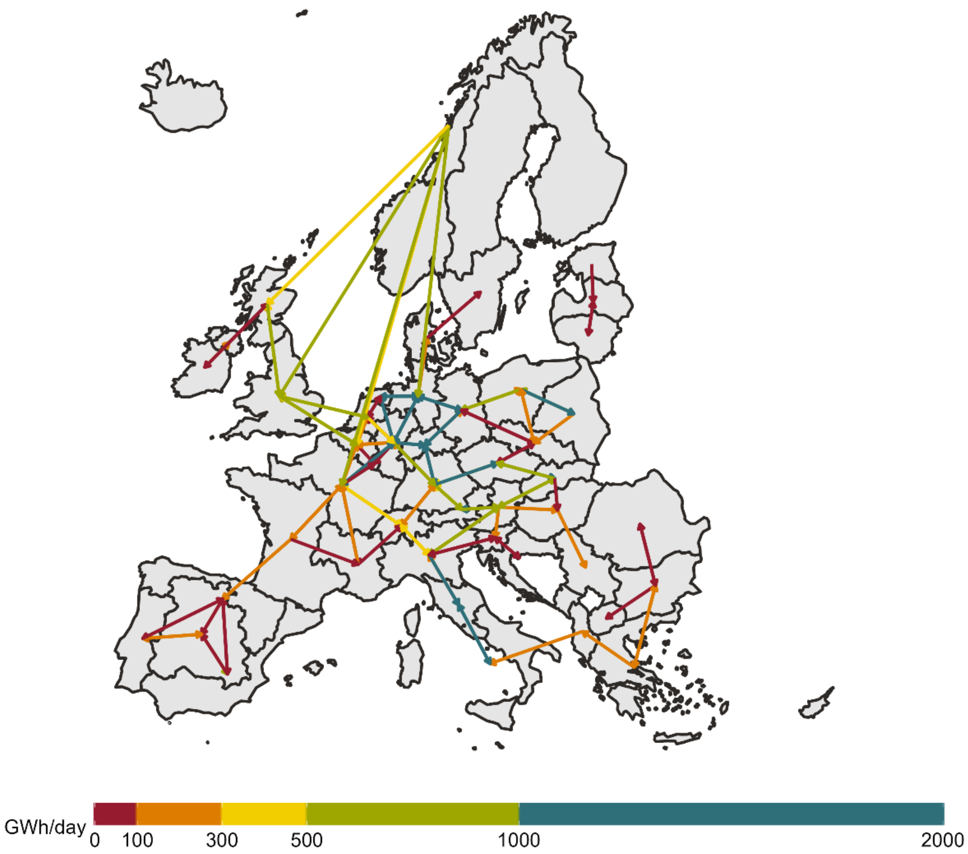
- **Import and exploitation potentials from outside the model regions:** Import capacities for methane, liquefied natural gas (LNG), biomethane, and hydrogen were integrated into the grids:

  - TYNDP 2024 data was used to determine the import potentials for methane, biomethane, and LNG, which were then connected to the corresponding nodes.

  - Hydrogen import potentials were similarly connected to the appropriate nodes.

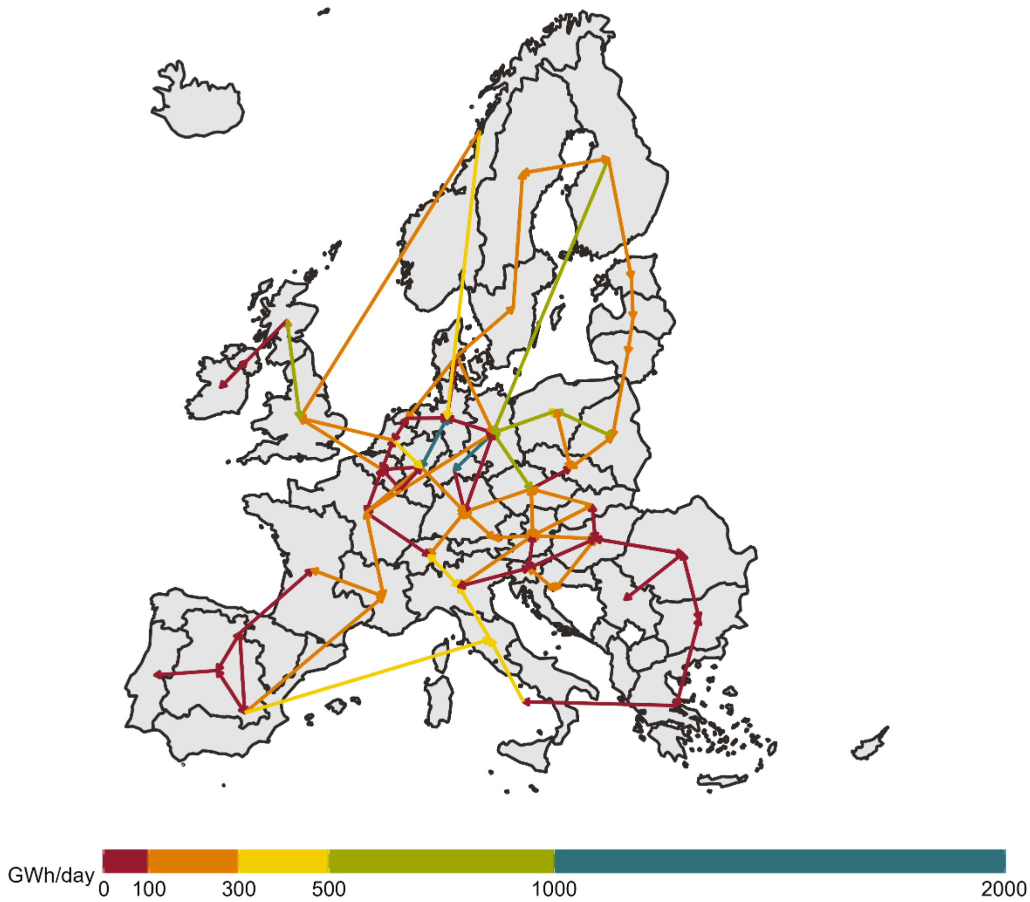
Figure 6 shows the development of the total internal trade capacities in the modelled regions.

Figure 4 Aggregated methane grid 2050



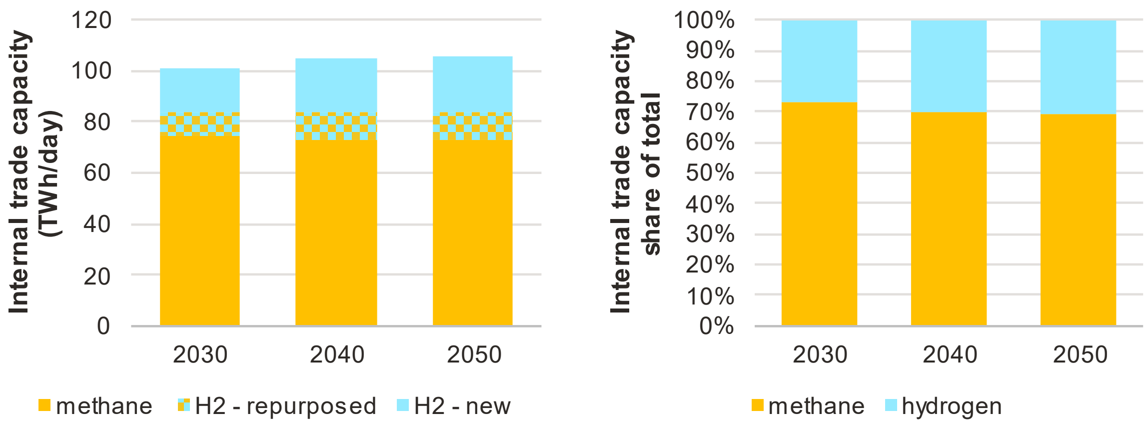
Source: Frontier economics

Figure 5 Aggregated hydrogen grid 2050



Source: Frontier economics

Figure 6 Methane and hydrogen internal trade capacity, EFTA+UK



Source: Frontier economics

Electricity transmission network

COMET considers restrictions for the transmission of electric energy by approximating net transfer capacities between model regions.

Data Sources

COMET's net transfer capacities for electricity between model regions are derived based on a number of sources (details below), and by using parts of the grid workflow of the open-source European energy system model PyPSA-EUR[6]. The PyPSA-EUR grid is build based on publicly available data from the ENTSO-E grid map[7], processed through a GridKit[8] extract. The dataset reflects the transmission network in Europe as of March 2022.

The dataset has been expanded by reviewing grid data manually to update it to 2024[9] and by incorporating the expansion projects listed in the TYNDP 2022, taking into account the envisioned commissioning year and the project status. As the TYNDP features projects with cross-border impact, the AC intra-country expansion is underestimated when only accounting for the TYNDP projects – therefore, AC intra-country capacities are expanded through a pro-rata approach, i.e., by applying the same expansion rate as the respective country's AC cross-country capacities. At the same time, the network is clustered to COMET's NUTS-1 level, based on the *cluster_network* functionality of PyPSA-EUR[10].

At this point the clustered network still consists of nominal capacity values for the AC network: To arrive at net transfer capacities, the network is scaled based on net transmission capacities provided by the ENTSO-E ERAA 2022[11]. More detail on the process is provided below.

In total, we represent the European electricity grid as an aggregated grid with 104 nodes, 186 AC and 56 DC transmission lines (in 2025[12]), representing the 380 kV and 220 kV level[13]. Where this leads to isolated regions at NUTS-1 level (e.g. Bremen in Germany), we have also considered 110 kV transmission lines. We assume standard transmission capacities for the different line types.

6 PyPSA-EUR, distributed under MIT license, copyright by Tom Brown (KIT, TUB, FIAS), Jonas Hoersch (KIT, FIAS), Fabian Hofmann (TUB, FIAS), Fabian Neumann (TUB, KIT), Marta Victoria (Aarhus University), Lisa Zeyen (KIT, TUB).

7 ENTSO-E: Interactive map available at https://www.entsoe.eu/data/map/.

8 GridKit, distributed under MIT license, copyright by Bart Wiegmans (2016). The GridKit extract is part of the PyPSA-EUR data bundle, processed by the PyPSA-EUR team, in particular Martha Frysztacki.

9 Through the ENTSO-E interactive map (https://www.entsoe.eu/data/map/).

10 The documentation of the PyPSA-EUR *cluster_network* script can be found here.

11 ENTSO-E (2023): ERAA 2022 | ERAA 2022 by ENTSO-E (entsoe.eu).

12 In 2050, our baseline network features 188 AC and 76 DC transmission lines between regions.

13 Other voltage levels >=220 kV are mapped to the 380 kV and 220 kV grid.

Calculation of net transfer capacities

The full network model is eventually processed to estimated net transfer capacities between NUTS-1 zones. This is done separately for the AC and DC network. For the AC network, the transmission capacity is derived using the following steps:

- **Network aggregation**: The full network is simplified to improve computational performance, but also to match it to the requirements of the overall energy system model. For this, our processing, based on PyPSA-EUR's clustering workflow, aggregates all tab lines to the nearest node. After this, all nodes within one zone are aggregated into one single node. Lines between the original nodes are ignored, this assumes a copperplate within the NUTS-1 zone. Subsequently, the voltage of all remaining lines is set to 380 kV and parameters of the lines are adjusted correspondingly. In a last step, parallel lines between two zones are aggregated to a single line, keeping the relevant transmission parameters constant. All these aggregation steps are based on PyPSA-EUR code (see Figure 7, illustrating the capacity expansion and the aggregation process).

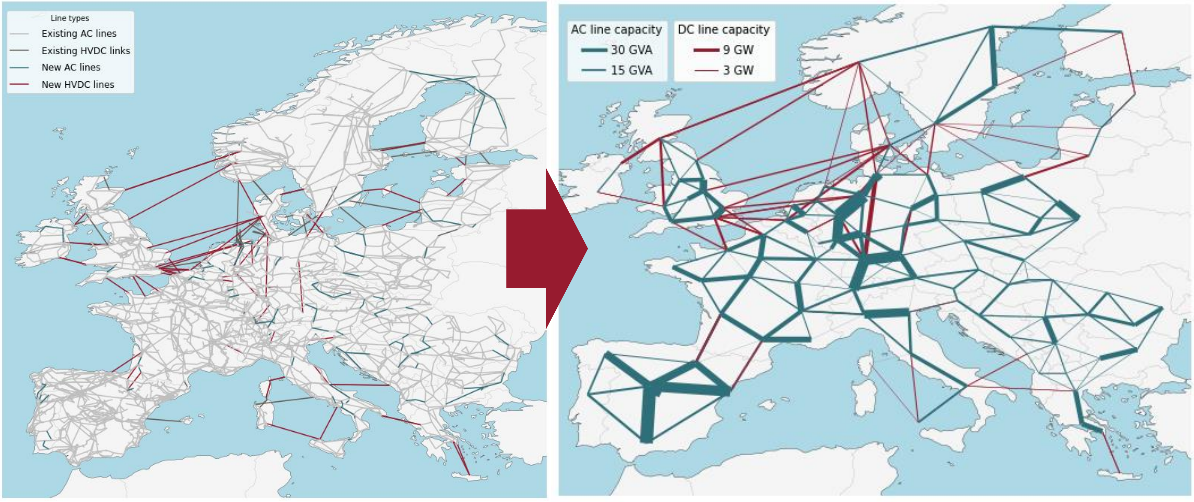
- **Calculation of Power Transmission Distribution Factors (PTDF)**: Based on the simplified network, we calculate the PTDFs of the network. PTDFs describe the impact of a change in the net position of one zone on all network elements of the simplified network model. This is implemented by using a PyPSA functionality[14].

- **Calculate maximum transmission capacity**: Using the simplified network model and the PTDFs, the maximum transfer capacities between two zones are calculated. To avoid overestimating the maximum capacities (which could occur due to the aggregation of the network, which could mask network congestions), we consider a maximum value equal to the nominal capacities themselves. Additional to this, we account for *n-1* security by reducing the available transmission capacity by 30% across the board.

- **Calculation of the net transfer capacity**: We calculate the net transfer capacity between two neighbouring regions by adjusting the maximum transmission capacities to match ENTSO-E's expected national NTCs from the ERAA 2022 analysis. For cross-border capacities, the maximum transmission capacities are scaled to match the respective country-to-country NTCs (proportional to line capacities). Intra-country capacities are scaled by a pro-rata approach, using the respective country's weighted average NTC-scaling factor (see Figure 8 for an illustration of the resulting grid).

[14] Function *determine_network_topology*, part of PyPSA, Copyright 2015-2024: 2015-2024 Tom Brown (FIAS, KIT, TUB), 2015-2021 Jonas Hörsch (FIAS, KIT), 2019-2024 Fabian Hofmann (FIAS, TUB), 2018-2024 Fabian Neumann (KIT, TUB), 2020-2024 Lisa Zeyen (KIT, TUB), 2020-2024 Martha Frysztacki (KIT), 2022-2024 Philipp Glaum (TUB), 2022-2024 Max Parzen (University of Edinburgh), 2016 David Schlachberger (KIT).

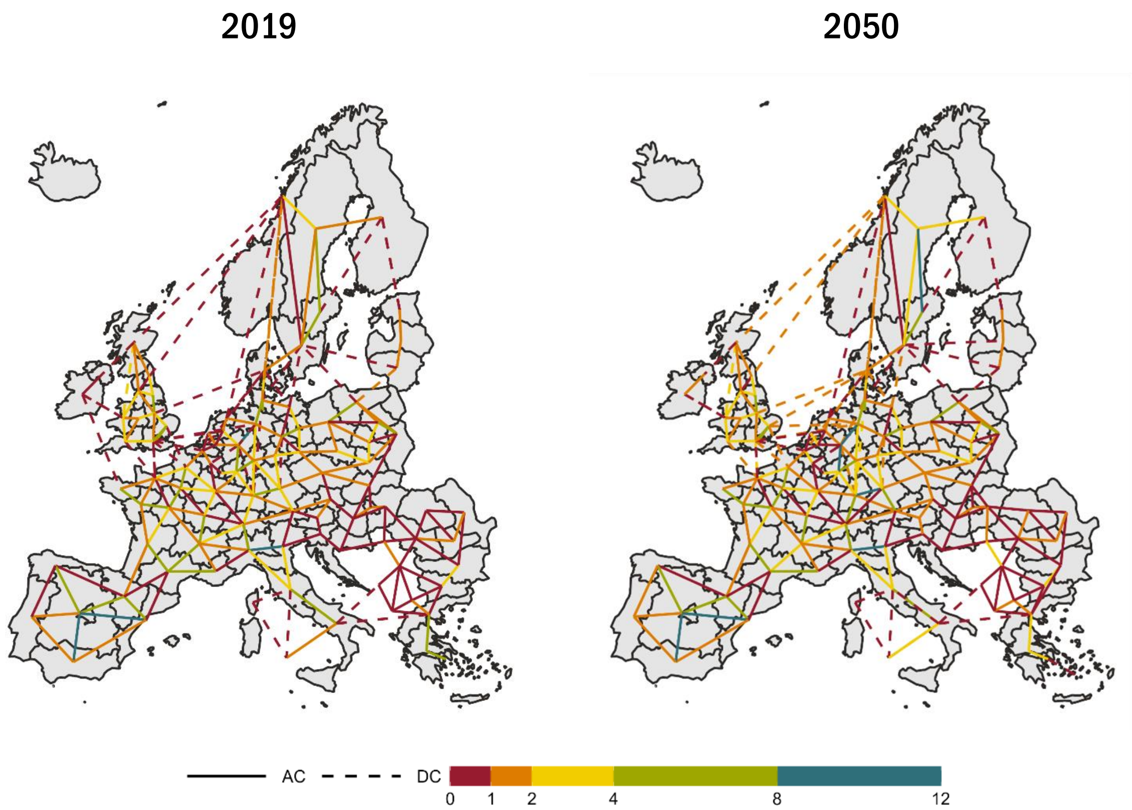
Figure 7 Illustration of the capacity expansion and the aggregation process of the baseline grid 2050 to our NUTS-1 target resolution



Source: Frontier Economics

Note: The clustered network on the right illustrates (unprocessed) nominal transmission capacities.

Figure 8 COMET electricity grid in different years



Source: Frontier Economics

A.5 Temporal granularity and representation

Typical weeks

To balance computational efficiency with temporal accuracy, we employ the tsam package[15] to generate representative time periods for the model. Using tsam, we generate four typical weeks with an hourly resolution, one for each season of the year. These typical weeks are used to capture the key temporal variations across all profiles considered in the, including:

- **Demand profiles:** Energy demand patterns by fuel and (sub)sector.
- **Climate data:** Variations in temperature, wind speed, and solar irradiance.
- **Renewable generation profiles:** Output profiles for solar photovoltaic (PV), wind, and run-of-river hydropower, reflecting seasonal and daily variability in resource availability.
- **Outages and availability:** Planned and unplanned outages of power generation units.

By doing so, we maintain a high level of detail regarding the system's operational behaviour across different seasons, while significantly reducing the computational burden of the model.

- **Data preprocessing:** First, we normalise the data across different attributes (e.g., demand, climate, etc.) to ensure they are on comparable scales. This helps to prevent certain data types from dominating the clustering process due to their larger values.
- **Time series aggregation:** tsam clusters hours based on their similarity using Ward's Hierarchical Agglomerative Clustering Method to generate typical periods for each season.
- **Rescaling:** After clustering the data into typical periods, we rescale the results to ensure the properties of the original time series (such as annual capacity factors) are preserved.
- **Output:** The result is a set of typical weeks, which condenses the full time series into a manageable form while still capturing key patterns.

Kalte Dunkelflaute (cold dark doldrums)

While time series aggregation allows for an accurate representation of total annual values, it does not take into account extreme weather situations that only occur every few years, and that put particular stress on the energy system.

Periods with prolonged low temperatures combined with low solar radiation and low wind speeds are called *kalte Dunkelflaute* (cold dark doldrums). With rising shares of variable

15 tsam: Distributed under MIT license. Copyright © 2016-2022 Leander Kotzur, Maximilian Hoffmann, Peter Markewitz, Martin Robinius, Detlef Stolten.

renewable energies and increasingly electrified final energy consumption, these periods become increasingly challenging: Electricity-based heating increases electricity demand while larger shares of the generation fleet might only have limited availability.

To assess the resilience of the energy system, we add a period representing a *kalte Dunkelflaute*. To do this, we analyse historical weather data spanning more than 40 years for temperature, wind speed and solar radiation. In combination with expected future capacity values for variable renewables and electric heating technologies, we identify the most relevant two-week period for assessing security of supply, based on residual electricity demand (total final demand minus variable renewables generation).

The analysis of periods of extreme weather allows us to draw conclusions regarding security of supply of different energy system configurations, for example: How much backup capacity is needed for periods of prolonged low variable renewables generation? To what extent can storage help bridge periods of high residual load?

Weighting and seasonal storage

Storage is used to balance energy demand and supply and shift available energy to times when it is most needed: If, for example, electricity demand is low during a windy night, the power generated by wind turbines is stored. During the day, when demand picks up, electricity is fed back into the grid. Seasonal storages, characterised by high capacity that can storage large volumes of energy, are used to balance energy supply and demand over long periods: Today, this is typically the case for large underground methane storages (such as depleted natural gas fields, aquifers, or salt caverns). These storage facilities can hold large quantities of methane that can be injected during low-demand periods (typically in the summer) and withdrawn during peak demand periods (winter).

COMET optimises the use of storage during typical weeks for each season. The seasons are connected such that, within capacity limits, storages can transfer energy stored at the end of each season into the next season. This ensures that energy can be used when it is most valuable: Energy produced or imported during times of low demand, such as summer, can be stored and used during periods of high demand, like winter.

Additionally, we apply a weighting system to different time periods: The four weeks representing summer, autumn, winter, and spring are scaled to match actual season lengths in a full year. The *Dunkelflaute* period is weighed according to its relative frequency according to the historical weather analysis. In total, the four seasons determine the typical operation of the energy system during the year, while the *Dunkelflaute* reflects an extreme period and determines what back-up capacities and technologies are needed to ensure security of supply during a stress period.

A.6 Final demand flexibility

The future energy system is expected to rely to an increasing share on electricity generation by variable renewables. To be able to integrate their generation into the system, a flexibilisation of the whole energy system is required. On the final demand side, flexibility is expected to be provided to a large extend by flexible charging (and discharging) of electric vehicles, and by the flexible operation of electric heat pumps. In the following, we sketch how these flexibility options are represented in the COMET model.

Vehicle charging

Electric vehicle charging (and discharging) is optimised as part of the overall system-cost minimisation: Within certain constraints and taking into account related costs, vehicles choose the most cost-optimal charging behaviour (minimising their own charging costs) and can feed electricity back into the grid.

The available flexibility of electric vehicles depends on several constraints:

- vehicles with demand response capabilities (i.e. connected to a smart meter and choosing to participate in smart charging)
- vehicles connected to the grid at a particular time
- charging requirements (e.g. minimal charging levels at the time of disconnection)
- availability for discharging (i.e. willingness to discharge)

We distinguish between three charging types: home, work, and road charging. While vehicles charged at home or work can do so flexibly in principle (depending on their availability for smart charging), road charging is inflexible. For home and work charging, we assume a typical connection pattern: home-charged vehicles are connected during the night, whereas work-charges vehicles are connected during the day. The connection patterns vary additionally depending on the type of day (workday, weekend, holidays) and the season.

Electric heating

Electric heat pumps are expected to be an increasing source of demand side flexibility in the future energy system. We model the useful energy demand of buildings based on regionally differentiated data for:

- building structure (type of building, e.g. single-family home, or office building)
- insulation levels (depending on the region and year)
- temperature profiles during the year.

These inputs are used to calculate the useful heat demand in all buildings that are heated with heat pumps. For the hourly dispatch, we assume that heat pumps can be operated flexibly within certain constraints, depending on:

- the share of heat pumps/households participating in flexible operation (restricted by the availability of smart meters)
- minimum and maximum constraints regarding the room temperature that has to be maintained.

While we assume that heat pumps can be operated flexibly, the actual availability of flexibility varies significantly throughout the year. While, first, heat pumps do not operate during the warmer period of the year, their flexibility is also significantly reduced during very cold episodes: With low outdoor temperatures, the heat loss of buildings is increased compared to milder temperature. This requires higher heat production. Additionally, the efficiency of heat pumps (expressed as Coefficient Of Performance, COP) declines with lower temperatures: A heat pump extracts heat from the outside air, ground, or water, even in cold weather, and transfers it inside. Heat pumps become less efficient as the temperature difference between the inside and outside increases. Both effects combined (higher heat loss and lower heat pump efficiency), means that during particularly cold periods there is typically little flexibility to shift the heating operation to hours with lower electricity prices as heat pumps are operating at (or close to) their capacity limit.

Annex B – Input assumptions

In this section, we describe important input assumptions for our model.

B.1 Techno-economic assumptions

Conventional fuel prices and import potentials

Fuel prices are derived from IEA's World Energy Outlook (2023) and complementary sources (see Table 1). The prices represent import prices, demand-supply balances in individual bidding zones can result in deviations from import prices (endogenous pricing).

Table 1 Fuel prices in Europe (€$_{2021}$/MWh$_{th(LHV)}$)

Fuel	2030	2040	2050
Coal[1]	8.5	7.6	6.7
Methane[1]	21.6	19.8	17.9
Lignite[2]	1.7	1.7	1.7
Nuclear[2]	3.4	3.4	3.4
Oil[1]	40.4	43.6	46.8
Biomass[3]	36.5	36.5	36.5

Source: 1: IEA - World Energy Outlook 2023 Announced Pledges scenario; 2: Frontier Economics and DNV (2024) for GLE; 3: Argus forward index (Sept. 2023; assumed real constant)

European import capacities for methane are derived from TYNDP 2024 (see Table 2). Following the war in Ukraine and due to the uncertain outlook, we have excluded energy imports from Ukraine to Europe.

Table 2 Methane import potentials (TWh)

Fuel and import region	2030	2040	2050
Natural gas			
Azerbaijan	228	228	228
Middle east	110	110	110
North Africa	574	574	574
Norway	1421	1089	1089

Fuel and import region	2030	2040	2050
Russia	380	380	380
Turkey	63	63	63
Turkmenistan	336	336	336
LNG			
Middle East	379	387	387
North Africa	221	200	200
North America	479	473	473
Other	386	403	403

Source: Frontier based on ENTSO-E & ENTSOG (2024): 20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios.

Import costs and potentials for renewable fuels

Import costs of renewable fuels are based on TYNDP 2024 Global Ambition scenario and Frontier Economics (see Table 3). Cost of importing PtH2 are differentiated between pipeline imports from North Africa and ship imports using the ammonia route (NH_3). Costs of ship imports therefore include the cost of cracking to reconvert ammonia into hydrogen.

Table 3 Renewable fuel prices (€$_{2021}$/MWh$_{th(LHV)}$)

Fuel and import region	2030	2040	2050
PtH2			
North Africa (via Pipeline) [1]	63.0	35.7	33.6
by ship (NH3) [2]	139.1	115.3	102.2
PtM			
by ship [2]	147.2	130.2	120.2
PtLiquids[3]	40.4	43.6	46.8

Source: Frontier based on 1: ENTSO-E & ENTSOG (2024): 20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios; 2: Frontier Economics and DNV (2024) for GLE; 3: IEA - World Enery Outlook 2023 Announced Pledges scenario

Import potentials for renewable fuels are derived from TYNDP 2024 (see Table 4). Imports of PtH2 and PtM by ship are optimised endogenously, assuming a market driven decision to convert hydrogen to methane overseas if this is cost efficient. We apply the limit in TWh$_{H2}$ with a 20% conversion loss if importing PtM. For example, ship import potentials in 2050 amount to 816 TWh$_{H2}$, which is the sum of 696 TWh$_{H2}$ in addition to 120 TWh$_{H2}$ (100 TWh$_{CH4}$ assuming 83% efficiency) of synthetic methane assumed in the TYNDP.

Table 4 Import potentials ($TWh_{(LHV)}$)

Fuel and import region	2030	2040	2050
PtH2 (North Africa via Pipeline)	23	381	662
PtM / PtH2 (by ship) TWh_{H2}	83	508	816
PtLiquids	79	157	189
Biomethane	17	45	90

Source: *Frontier based on ENTSO-E & ENTSOG (2024): [20230704 – Draft Supply Tool (EU-level)] and [20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios].*

Technology costs conversion technologies

We assume the following cost for building renewable and low-carbon fuel production facilities (see Table 5).

Table 5 Technology costs conversion technologies

Technology	CAPEX (€$_{2021}$/kW)			OPEX	
	2030	2040	2050	€$_{2021}$/kW/a	€$_{2021}$/MWh
Bioliquification[1]	3,418	2,499	2,100	104	1.13
Biomethanisation[4]	1,200	1,150	1,100	20	2.5
Electrolysis[2]	550	375	325	14	0.01
Power-to-liquid[1]	650	505	434	34	0
Power-to-methane[3]	633	431	374	16	0.01
Steam methane reforming[4]	720	600	600	12	4

Source: *1: Frontier Economics for FVV (2022) - [Fuel Study IVb]; 2: ENTSO-E & ENTSOG (2024): [20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios]; 3: ENTSO-E & ENTSOG (2024): [20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios], assuming 15% cost uplift compared to H2 electrolysis; 4: Danish Energy Agency - [Technology catalogues]*

Renewable electricity costs and potentials

The assumed costs of renewable electricity sources are based on IEA's World Energy Outlook 2023 (see Table 6).

Table 6 RES-E technology costs

Technology	CAPEX (€$_{2021}$/kW)			OPEX	
	2030	2040	2050	€$_{2021}$/kW/a	€$_{2021}$/MWh
Solar PV	635	550	465	10	0
Onshore wind	1,452	1,426	1,400	14	0
Offshore wind	1,983	1,748	1,513	37	0

Source: Frontier based on IEA - World Energy Outlook 2023 (Announced Pledges Scenario).

The allowed range of capacity buildup of wind and solar power installations across Europe in our Baseline scenario is based on the trajectories outlined in the TYNDP 2024 Draft Supply Inputs. These ranges constrain the capacity buildup on a country-level by providing a minimal and maximum value in each reference year (see Table 7).

Table 7 RES-E capacity limits EU27 (GW)

Technology	2030	2040	2050
Solar PV	497 - 780	776 - 1,332	1,016 - 2,192
Onshore wind	305 - 378	406 - 640	452 - 830
Offshore wind	97 - 241	251 - 436	369 - 661

Source: ENTSO-E & ENTSOG (2024): 20230704 – Draft Supply Inputs for TYNDP 2024 Scenarios.

Biomass potentials are based on the TYNDP 2024 Draft Supply Inputs, increasing from 1,967 TWh in 2030 to 2,301 TWh in 2050.[16] We limit biomass consumption for biomethanisation to 572 TWh in 2030, increasing the limit to 1619 TWh in 2050[17].

Conventional electricity generation technologies and large-scale electricity storage

Table 8 outlines the investment and running costs of conventional electricity generation and storage technologies used in the model.

16 Frontier based on EC State of the Energy Union Report 2023 and ENTSO-E & ENTSOG (2024): 20230704 – Draft Supply Tool.

17 ENTSO-E & ENTSOG (2024): 20230704 – Draft Supply Tool. Calculated from biomethane production assuming 66% conversion efficiency. Following the TYNDP 2024 public consultation for the scenario input data, we use the full potential

Table 8 Conventional electricity generation and storage technology costs

Technology	CAPEX (€$_{2021}$/kW)			OPEX	
	2030	2040	2050	€$_{2021}$/kW/a	€$_{2021}$/MWh
Utility scale battery (4h)[1]	766	632	497	33	0
CCGT + CCS[2]	2,578	2,328	2,079	90	4
CCGT[2]	832	832	832	23	2

Sources: 1: NREL Advanced scenario; 2: IEA - World Enery Outlook 2023 Announced Pledges scenario & Frontier Economics

Carbon capture and storage costs and potentials

We explicitly model the deployment of carbon capture technologies. Underground storage capacities do not represent a limit to the deployment of carbon capture[18] and we assume that land-based transport of CO_2 via trucks or pipelines will match the requirements. We differentiate between

- carbon capture in final demand sectors, e.g. industrial processes;
- carbon capture in power generation (post combustion);
- carbon capture to produce blueH2;
- carbon capture in biomethanisation (BECC[19]); and
- carbon capture through direct air capture (DAC).

The potential for carbon capture in **final demand sectors** is assumed to vary between 60- and 70%[20], depending on the sub-sector (carbon capture is only possible for processes with a high concentration of CO_2) and the fuel used (for example the presence of impurities such as sulphur in coal can complicate the capture process, often resulting in lower overall capture rates). The costs of CCS in final demand sectors has been derived from Goldman Sachs' Carbonomics study[21] and vary between 50 €$_{2021}$/tCO_2 and 142 €$_{2021}$/tCO_2 captured. Additionally, 21 €$_{2021}$/tCO_2 for transportation and storage are considered.

Costs of carbon capture for **power generation** and **steam methane reforming** (blueH2) are included in the technology specific costs shown above. We do not limit the potentials to deploy these technologies. Carbon capture costs in biomethanisation (**BECC**) are assumed to be 100

18 CATF (2023) – Unlocking Europe's CO2 Storage Potential – Clean Air Task Force (catf.us)

19 Better known under the related abbreviation BECCS, which indicated the combination of carbon capture with carbon storage.

20 CCS technologies are designed to capture between 85% and 90% of CO_2 from emissions at power and industrial plants. We lower this value as it is economically not viable to installed carbon capture technologies at all sites.

21 Carbonomics Innovation, Deflation and Affordable De-carbonization (goldmansachs.com)

€$_{2021}$/tCO_2. The potential to use BECC is linked to the potential to produce biomethane. **DAC** represents a last-resort option the model can use to meet the binding emission limits. It is therefore not modelled as investment option but can be deployed as needed at the cost of 200 €$_{2021}$/ tCO_2. The maximum potential to use DAC amounts to 153 MtCO_2 in 2040 and 250 MtCO_2 in 2050 and has been derived from the EC Impact Assessment.[22]

B.2 Emission limits

In this section, we describe the modelling and compliance with emission limits.

EU emission budget

We model emission targets as annual emission constraints limiting the use of fossil fuels corresponding to their respective GHG content. We derive annual emission limits corresponding to the scope of our model referring to scenario 3 of the EU Commission's Impact Assessment for a 90% emission reduction until 2040: Land-use and land-use change and forestry (LULUCF) net-removals are estimated to reach ca. 330 MtCO_2-eq in 2050. The model does not capture non-energy related emissions from agriculture, which are assumed to decrease from 385 MtCO_2-eq in 2015 to 249 MtCO_2-eq in 2050. Accounting for these out-of-scope emissions results in a limit for in-scope emissions of 84 MtCO_2-eq in 2050. Table 9 shows the annual emission limits applied in COMET.

Table 9 COMET annual emission limits (MtCO_2-eq)

	Emissions excluding LULUCF	LULUCF	Net GHG emissions	Emissions outside COMET	Emission budget for COMET
1990	4,867				
2015	3,914	-322	3,592	385	3,529
2030	2,410	-319	2,091	317	2,093
2040	804	-317	487	271	533
2050	317	-333	0	249	84

Source: Frontier Economics based on European Commission Impact Assessment – Scenario 3.

[22] 2040 value based on scenario S3 of the EC's impact assessment on possible pathways to reach climate neutrality by 2050.

Upstream methane emissions

Methane is, next to CO_2, the second most relevant greenhouse gas. The EU has taken action to regulate the methane emissions in the energy sector: The EU Parliament adopted a provisional political agreement with EU countries on a new law that aims at reducing methane emissions in the energy sector. The regulation shall apply to imported oil, gas and coal from 2027 onwards. In a first phase, the European Commission shall set up a transparency data base. In the second and third stage, taking effect on 1 January 2027, monitoring, reporting and verification measures will be applied to exporters to the EU. A maximum methane intensity value shall be applied to companies producing oil, gas and coal by 2030.[23]

The threshold of 0.2% in the context of methane emissions is often referred to as the methane intensity standard. This standard means that no more than 0.2% of natural gas produced by a facility should be lost through methane emissions. The methane emissions intensity of oil and gas production varies widely. Norway and the Netherlands have the lowest emissions intensities. Countries in the Middle East, such as Saudi Arabia and the United Arab Emirates, also have relatively low emissions intensities.[24]

As the thresholds, that will eventually be applied to imports of gas, are undefined, we have not included an explicit modelling of upstream methane emissions in our analysis. Given the plans to implement maximum limits in Europe, we do not assume that upstream methane emissions will be of significant importance going forward nor would their explicit consideration in our analysis alter any of our conclusions in this analysis.

B.3 Supply assumptions

We maintain a regularly updated database of conventional power plants in Europe with their locational and technical data as well as decommissioning dates if known. These plants are mapped to their corresponding NUTS1 regions. Average power plant availability is set based on historical data obtained from ENTSO-E.

For existing RES-E technologies, we use aggregated country-level capacities from IRENA and regionalise them to NUTS1 regions based on average capacity factors, assuming that technologies are more likely to be deployed in larger numbers where they can be utilised most.

We utilise climate data from the ECMWF ERA5 dataset, including hourly air temperature and capacity factors for photovoltaic, onshore wind, and run-of-river technologies. These capacity factors are aggregated from NUTS2 to NUTS1 regions using area-weighted averages. Offshore wind capacity factors in maritime regions are mapped to the nearest corresponding NUTS1 regions.

23 European Commission (2024): EU Regulation to reduce methane emissions in energy sector, https://ec.europa.eu/commission/presscorner/detail/en/qanda_24_2258

24 https://www.iea.org/reports/global-methane-tracker-2024/key-findings

Annex C – Final energy demand modelling

In this Annex, we provide additional information on the assumptions underlying the TYNDP's final demand modelling and our own perspective on some of these assumptions.

C.1 Technical process to get final demand figures

Get TYNDP 2024 final demand figures with the Energy Transition Model (ETM)

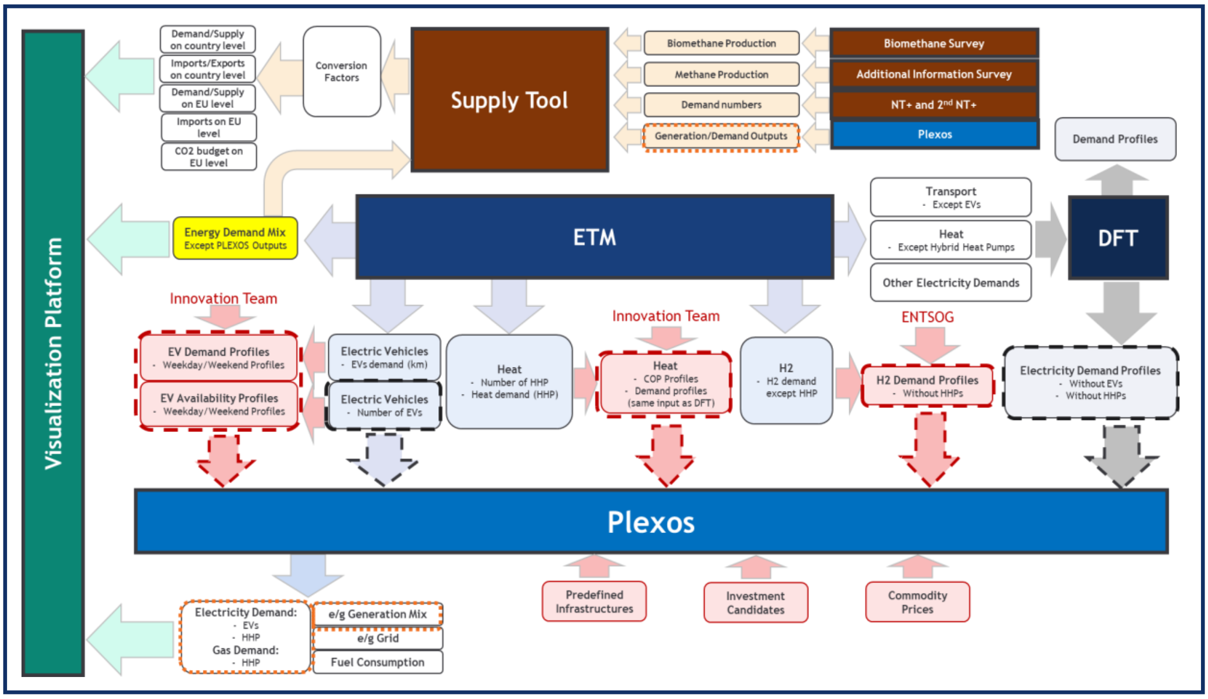
The TYNDP 2024 scenarios use Quintel's Energy Transition Model (ETM)[25] to estimate the final energy demand in 2040 and 2050. The ETM is based on six major sectors (households, buildings, transport, industry, agriculture and other), divided into more than 30 subsectors and processes.

The TYNDP 2024 used the final demand output of the ETM as an input for its own energy system modelling (see Figure 9). This final demand analysis is based on 323 unique parameters per country, scenario and year – in total adding up to more than 45,000 input values (two scenarios (Global Ambition and Distributed Energy), two scenario years (2040 and 2050), plus the base year assumptions for the 27 EU countries and the UK[26]).

[25] See https://energytransitionmodel.com/.

[26] United Kingdom was included in the version of the 04th of July 2023 of the demand scenario (https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2023/07/20230704-Draft_Demand_Scenarios_TYNDP_2024.xlsb.zip) but was removed from the final version of the demand scenarios after public consultation (https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/01/Demand_Scenarios_TYNDP_2024_After_Public_Consultation.xlsb.zip).

Figure 9 Overview of modelling methodologies used in the TYNDP 2024



Source: *Overview of 2024 Innovations - Scenarios 2024 Modelling Methodologies, ENTSO-E and ENTSO-G, November 2023*

To be able to access all final demand provided by the ETM, we used the ETM's application programming interface (API).[27] The ETM data format difference from the aggregated data published in the TYNDP. To align with the categorisation of the TYNDP, we aggregated the more detailed ETM energy carriers into groups matching those of the TYNDP.

The ETM also provides hourly final demand values for specific energy carriers (electricity, hydrogen, and methane).[28] We used the this data to build hourly demand profiles by sector and subsector.

This process for retrieving final demand figures using the ETM API has led to minor differences compared to the TYNDP 2024 values:

- Given the lack of available information regarding the aggregation of ETM data performed by the TYNDP, we aggregated the ETM output based on its data labels to match, a) the labels used in the TYNDP tables, b) match total TYNDP values, as closely as possible. This resulted in our aggregated ETM data very closely approximating the aggregated data published by the TYNDP.

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27 Our dataset relies on API calls conducted on the 04th of March 2024 for the main TYNDP scenarios and on the 06th of March for our "what-if" scenarios. We therefore used the version of the ETM available at that moment.

28 For an example of an output of this downloadable file for electricity without any specific input values for any parameter see: https://energytransitionmodel.com/scenario/data/data_export/hourly-curves-for-electricity

- The TYNDP scenarios were built with a version of the ETM available during the summer 2023. The ETM has been updated several times since then. Given that only the latest version of the ETM is available at any given time, we used an updated version compared to the TYNDP. Additionally, the model was updated during the course of this study, including some important modelling changes in the household and building sectors, resulting in a decrease of final demand for district heating.

We therefore made some additional adjustments to get final demand figures comparable with the TYNDP (see the following section).

Additional adjustments of ETM final demand data

To complement and align our final input data with TYNDP values, we performed the following steps:

- Norway and Switzerland are not included in the original ETM data set. We therefore rely on national statistics for the base year 2019 for these two countries. For splitting final demand in TYNDP categories and forecasting 2040 and 2050, we use trends in comparable countries that are included in the TYNDP data:
  - For Norway, we use 2019 production and consumption, energy balance and energy account data from *Statistics Norway*[29]. This data sets provides final demand figures for the industry, transport and other sectors for seven energy carriers and sources (coal, methane, oil, biofuels, waste, electricity, and district heating). We use ETM data for Sweden's demand development as a proxy to forecast final demand for Norway.
  - For Switzerland, we use energy balance data from the Swiss Federal Office of Energy[30]. This dataset provides final demand figures for five sectors (buildings, households, industry, agriculture and transport) by energy carrier (including liquids, methane, electricity, heat, waste, and hydro power). We use ETM data for Austria's demand development as a proxy to forecast final demand for Switzerland.
- The ETM model includes wasted heat from heat storages and distribution networks in its final demand numbers (e.g., unused (residual) heat from the industry).[31] As these values do not reflect actual final demand (and are also not included in the TYNDP final demand data), we remove them from the ETM final demand values.
- We observed significant differences between ETM and TYNDP final demand values in 2040 and 2050 for the industry subsector *others* for all European countries, and for *fertilizers*, *chemicals* and *refineries* for the Netherlands. We assume they result from

29 See https://www.ssb.no/en/statbank/table/11561.

30 See https://opendata.swiss/en/dataset/energiebilanz-der-schweiz/resource/1957ce24-bc06-40f8-a630-6db5bee3c419.

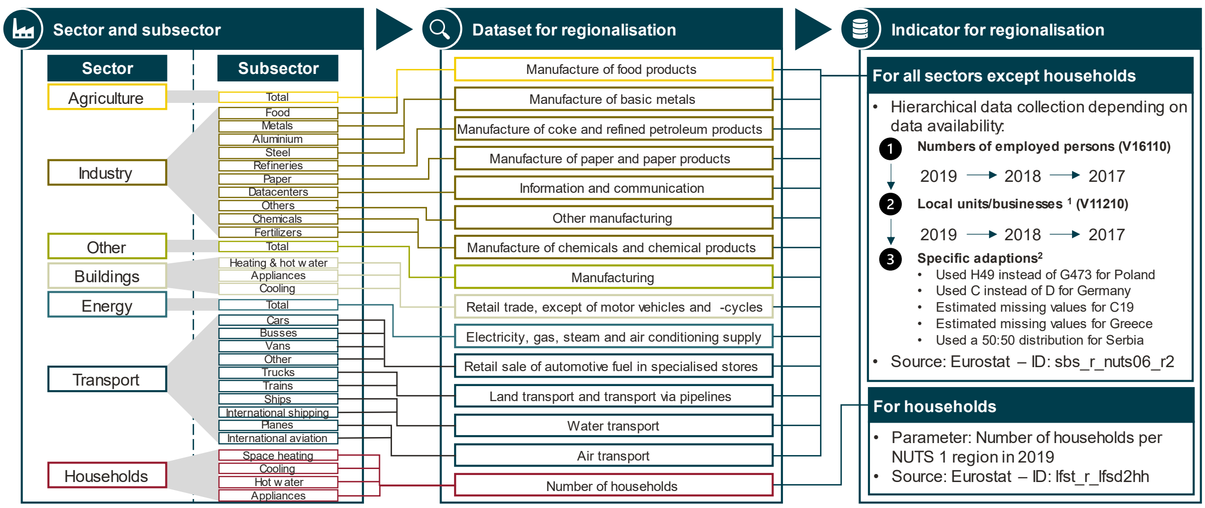
31 See the ETM documentation on 'Heat storage' accessible at this page: https://docs.energytransitionmodel.com/main/heat-networks and for industrial residual heat here: https://docs.energytransitionmodel.com/main/residual-heat-industry

modelling changes in the ETM compared to the version used by the TYNDP. To align with TYNDP values, we use for these cases the TYNDP final demand values directly rather than the ETM output.

C.2 Final demand regionalisation

To break down the country-level final demand to NUTS1 regions, we use the data sets outlined in Figure 10 as proxies for the different (sub)sectors. Due to varying data availability per country, we apply a hierarchical data collection method. Specifically, we use data sourced from Eurostat (ID: sbs_r_nuts06_r2), prioritising *Number of Employed Persons* (V16110), followed by *Local Units/Businesses* (V11210), using the most recent data available from the years 2019, 2018 and 2017. Additionally, we make specific adaptations where necessary. For the household sector, we use the *Number of Households per NUTS1 region* as a proxy, drawing from Eurostat (ID: lfst_r_lfsd2hh).

Figure 10 Proxies used to regionalise demand to NUTS1 regions



Source: Frontier Economics.

Note: 1) Local units refers to the number of businesses operating in the specified area; 2) H49 = Land transport and transport via pipelines, G473 = Retail sale of automotive fuel in specialised stores, C = Manufacturing, C19 = Manufacture of coke and refined petroleum products, D = Electricity, gas, steam and air conditioning supply. To derive estimates we distributed the difference between the nuts0 value and the sum of all available NUTS 1 values equally among the missing NUTS 1 areas. As at most two NUTS 1 values were missing within one country-sector combination, this estimation seems rather robust.

Annex D – Cost comparison approach

In this Annex, we elaborate on the approach of the indicative cost comparison between the *Baseline* (with final demand based on the TYNDP Global Ambition scenario) and the *High Electrification* scenario (based on the TYNDP Distributed Energy scenario). Any cost changes in the energy conversion sector resulting from changes in final demand (e.g. higher expanses for increased wind capacity covering higher electricity demand) are captured as part of the COMET model. Changes in investment costs for end-user appliances (e.g. for heat pumps instead of gas boilers or an electric truck instead of an hydrogen fuelled truck) are not part of COMET. These cost differences (mainly differences in investment costs, and O&M costs other than energy) are calculated outside the model by a separate analysis. The total cost comparison combines both aspects.

D.1 General approach

The approach for calculating the cost difference between both scenarios is similar across the considered subsectors of the ETM. For both scenarios, we calculate:

- Annuity costs of the EU-wide total investments in appliances (e.g., vehicles and heating technologies) and energy efficiency measures (e.g., insulation of buildings) in the most relevant sub-sectors[32]
- Annual maintenance costs for end-user appliances

Both cost components are summed up for the year 2030 to 2050 and discounted back to the year 2021.[33] The total costs of the two scenarios are then subtracted from each other (*High Electrification* minus *Baseline* scenario).

The sector-specific annual costs are determined as follows:

1. For the reference years 2019, 2030[34], 2040, and 2050 we calculate the EU-wide number of end-user appliances (and level of efficiency investments) for each scenario and year, differentiated by technology and fuel type. These values are based on country- and year-specific technology splits[35] in combination with country- and year-specific estimates for the subsector size derived from subsector energy demands.[36] This calculation accounts

32 Sectors with the largest delta in final energy demand.

33 The applied deflation rate is 5%

34 Since the ETM does not provide demand parameters or demand output for the year 2030, the number of units for that year is estimated using a weighted average of the 2019 quantities and the 2040 quantities of TYNDP's Global Ambition and the Distributed Energy scenarios. This approach reflects that the TYNDP scenarios are identical until 2030 and only begin to diverge thereafter.

35 From ETM demand parameters.

36 From ETM demand output.

for differences in the technology mix as well as differences in the absolute quantities of units between both scenarios.

2. These calculated quantities for year- and scenario-specific technologies are then multiplied by the technology-specific investment costs per unit, broken down to annual costs for the reference years by applying an annuity factor.[37] Technology-specific annual maintenance costs are added thereafter.

3. The annual costs of the technologies between the reference years are obtained through interpolation.

D.2 Sectors specific calculations

The calculation of the scenario- and year-specific number of appliances and insulation levels differs slightly between sectors and subsectors, depending on the ETM associated methodology and available demand parameters. These differences in the calculations of quantities are explained in the following subsections.

Households

For the households and buildings sector, insulation and space heating are considered in the cost analysis.

Household space heating specific differences/details compared to the general approach:

- In the calculation of cost differences in household space heating, the appliances mentioned in Step 1 of the general approach correspond to different types of household heating units.[38]
- Steps 2 and 3 coincide with the description of the general approach.[39]

Table 10 shows an extract of the relevant cost data (values exclude fuel costs which are covered in the COMET model).

[37] The applied annuity factors result from the technical lifetime of the technology (retrieved from the ETM) and a WACC of 5%.

[38] Condensing combi boiler (gas), condensing combi boiler (hydrogen), air heat pump, ground heat pump, hybrid air heat pump (gas), hybrid air heat pump (hydrogen), ground heat pump PVT, wood pellet boiler, electric heater, gas-fired heater, oil-fired heater, coal-fired heater. The ETM further lists district heating as a technology, which is not considered in the cost comparison as this would require modelling a heating network.

[39] Costs for initial investments and maintenance are taken from the ETM's internal technology specific technical and financial property files and https://energytransitionmodel.com/passthru/1162015/production_parameters.csv.

Table 10 Capital costs and O&M costs for space heating units (households)

Technology	CAPEX (k€$_{2019}$/unit)	OPEX (k€$_{2019}$/unit/a)	Thermal capacity, (kW/unit)
Condensing combi boiler (gas)	2.13	0.10	22.00
Condensing combi boiler (hydrogen)	2.08	0.10	22.00
Air heat pump	9.10	0.10	10.00
Ground heat pump	13.90	0.10	10.00
Hybrid air heat pump (gas)	3.82	0.20	5.00
Hybrid air heat pump (hydrogen)	6.50	0.20	5.00
Ground heat pump with PVT	12.42	0.10	8.00
Wood pellet boiler	3.03	0.16	10.00
Electric heater	0.30	-	6.00
Gas-fired heater	1.30	0.09	22.00
Oil-fired heater	2.10	0.06	10.50
Coal-fired heater	1.98	0.06	9.90

Source: TYNDP2024, ETM.

Household insulation specific differences/details compared to the general approach:

- Step 1: we calculate the total living space in the EU by household type (types of residence in the ETM are apartments, corner houses, detached houses, semi-detached houses, and terraced houses).
- In Step 2, we calculate the insulation improvement for each year and residence type compared to the previous year:
    - First, we multiply the EU-wide living space per type (calculated in step 1) with the difference in the average insulation level[40] between the current and the previous reference year (e.g., if households with a total area of 80 million square meters

[40] The different type of residences in the ETM are apartments, corner houses, detached houses, semi-detached houses,

improve their average insulation level from 20% to 40%, we end up with a total improvement of 160 million percentage points times sqm).[41]

- Second, to obtain the total costs, the total change of the insulation level is multiplied by the insulation costs per percent of heat savings per square meter (e.g., assuming 4.2 EUR/sqm/1pct-pt saving, total costs are 672 mn EUR).[42]

- Step 3: We assume that the begin of insulation work is equally distributed between two reference years. No need for reinvestment is assumed.

We base our assumption for insulation costs on the data used in the European Commission's impact assessment for the 2040 climate targets.[43] The ETM does not provide information about the level of insulation of individual units, nor does the EC data differentiate between different building types. Therefore, we simplify the analysis by assuming that average renovation costs per square meter and %point energy saved amount to the simple average of costs used by the EC for different insulation levels in the centre/west region of Europe. In short, the costs of insulation are assumed to amount to **4.2 EUR/sqm/1pct-pt of energy saved**.

Buildings

For the commercial buildings sector, we account for insulation and space heating costs in the analysis.

Buildings space heating specific differences/details to the general approach:

- In the calculation of cost differences from building space heating, we calculate investment and O&M costs (except fuel which is covered in the COMET model) for the different types of heating units[44]. This is computed by using the TYNDP/ETM technology splits and by extrapolating the European buildings thermal demand from 2019[45] with the scenario-specific insulation rates per year.

- Steps 2 and 3 coincide with the description of the general approach.[46]

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41 This value is adjusted in case of an increase or decline of the total number of residences of a particular type.

42 The insulation costs per percent of heat savings per square meter is calculated as an average value from E3Modelling (2024): Supplementary information. Technology assumptions on energy used in the analysis of SWD(2024) 63 final.

43 Based on E3Modelling (2024): Supplementary information. Technology assumptions on energy used in the analysis of SWD(2024) 63 final.

44 Collective heat pump, condensing combi boiler (hydrogen), air heat pump (gas), air heat pump, hybrid air heat pump (gas), hybrid air heat pump (hydrogen), water heat pump with TS, wood pellet boiler, electric heater, gas-fired heater, oil-fired heater, coal-fired heater. The ETM further lists district heating as a technology, which is not considered in the cost comparison as this would require modelling a heating network.

45 Based on JRC-IDEES-2021.

46 Costs for initial investments and maintenance are taken from the ETM's internal technology specific technical and financial property files and https://energytransitionmodel.com/passthru/1162015/production_parameters.csv.

Table 11 Capital costs and O&M costs for space heating units (non-residential)

Technology	CAPEX (k€$_{2019}$/unit)	OPEX (k€$_{2019}$/unit/a)
Collective heat pump	282	7
Condensing combi boiler (hydrogen)	60	3
Air heat pump (gas)	201	31
Air heat pump	1,652	18
Hybrid air heat pump (gas)	679	36
Hybrid air heat pump (hydrogen)	1,156	36
Water heat pump with TS	99	7
Wood pellet boiler	247	12
Electric heater	13	0
Gas-fired heater	23	2
Oil-fired heater	65	2
Coal-fired heater	100	3

Source: TYNDP2024, ETM.

Building insulation specific differences/details to the general approach:

- The ETM considers only one type of commercial building. Hence, the EU-wide scenario- and year-specific number of buildings does not have to be further distinguished by type (contrary to the calculations for household insulation).
- Steps 2 and 3 are equivalent to household insulation calculations, without a distinction by building type.[47]

Transportation

For the transportation sector, we analyse passenger transport cars, freight transport trucks and vans in our cost analysis. The calculation of the cost differences is identical with the general approach. The details of the calculation for all subsectors are summarised below.

[47] The average floor size of commercial buildings is retrieved from https://building-stock-observatory.energy.ec.europa.eu/factsheets/. The insulation costs per percent of heat savings per square meter coincide with the ones from the household insulation calculation.

Transportation specific differences/details compared to the general approach:

- For the calculation of cost differences for passenger and freight transportation in Step 1, we differentiate different technologies corresponding to individual fuel types. Since the ETM demand parameters do not contain the number units, we calculate them using an external source[48] for the reference year 2019 in combination with scenario specific growth rates of travelled km per transportation type (available from the ETM).

- Steps 2 and 3 coincide with the description of the general approach.[49]

Table 12 shows the investment costs of different transport options per transport segment.

Table 12 Capital costs for transport technologies (k€$_{2019}$/unit)

Technology	Passenger cars		Freight (Trucks[1])		Freight (Vans[2])	
	2030	2050	2030	2050	2030	2050
Electric	30.44	24.77	118.31	96.72	69.74	54.05
Hydrogen	29.74	26.42	70.97	65.61	44.46	40.01
Diesel	18.48	18.48	62.42	62.42	29.75	29.75
Gasoline	16.62	16.62	55.65	55.65	26.47	26.47
LPG	20.94	19.23	66.67	61.74	36.81	33.02
Compressed gas	17.69	17.48	65.77	65.10	28.24	27.88

Source: TYNDP 2024, ETM, Frontier Economics for FVV (2022) - Fuel Study IVb.
Note: 1: 16 - 40t "Long Haul"; 2: Light commercial vehicles (N1).

Assumptions for future cost reductions (learning curves) are subject to a high level of uncertainty. Our calculation of cost differences is therefore an **indication only**.

Industry

For industry, the ETM sub-sectors *chemicals* and *other industries* are considered in the cost analysis. The calculation methodology of the cost differences is equivalent for both subsectors and is summarised in the following.

Industry specific differences/details to the general approach calculations:

48 Eurostat (DOI:10.2908/tran_r_vehst; accessed 05.09.2024).

49 Costs for initial investments are taken from Frontier Economics for FVV (2022) - Fuel Study IVb. Maintenance costs are taken from the ETM's internal technology specific technical or financial property files and Van den Bulk, J (2009): A cost- and benefit analysis of combustion cars, electric cars and hydrogen cars in the Netherlands.

- The units, differentiated by technology/fuel type, correspond to different process heat appliances.[50] As the ETM demand parameters do not contain quantities for the different heating units, they are derived from the scenario and year-specific fuel demands of the sub-sectors and the capacity per heating unit.

Steps 2 and 3 follow the general approach.[51]

Table 13 Capital and O&M costs for industrial heating units (chemicals / other)

Technology	CAPEX (k€$_{2019}$/unit)	OPEX (k€$_{2019}$/unit/a)	Thermal capacity (MW/unit)
Electric boiler	3,000	105	50
Hydrogen-fired heater	6,000	100	100
Gas-fired heater	6,000	100	100
Biomass-fired heater	20,067	100	100
Coal-fired heater	20,067	100	100
Oil-fired heater	6,000	100	100

Source: TYNDP 2024, *ETM*

50 Electric boiler, hydrogen-fired heater, gas-fired heater, biomass-fired heater, coal-fired heater and oil-fired heater.

51 Costs for initial investments and maintenance are taken from the ETM's internal technology specific technical and financial property files.

Annex E – Licence notices

- ECMWF Reanalysis v5 (ERA5): Regulated under Regulation (EU) No 1159/2013 and under the ECMWF Agreement. The analysis performed for this study contains modified Copernicus Atmosphere Monitoring Service information 2019.

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