TECHNOLOGY CATALOGUE

Nordic Clean Energy Scenarios

Nordic Energy Research

About this publication

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Ea Energy Analyses was project lead for providing internally consistent and validated technology data for the scenario analyses. The most important technology assumptions are presented in this technology catalogue.

Ea Energy Analyses was responsible for the chapters concerning power and district heating, transport and green fuels. Energy Modelling Lab was responsible for the chapter on industry, whereas VTT and Thema contributed to reviewing the catalogue.

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Nordic Energy Research

List of Content

1 The Nordic Clean Energy Technology Catalogue

This publication summarizes the research, data collection, validation and synthesis performed under Work Package 2 (WP2) of the Nordic Clean Energy Scenarios (NCES) project. Within the NCES framework, WP2 revises, and structures relevant technology data used as input to the modelling activities.

The purpose of this report goes beyond the mere cataloguing of energy conversion technologies; data is rather restructured to obtain meaningful cost indicators that allow an easier understanding of the modelling results. The overarching aim is to compare well-established and promising technologies by providing the reader with a key for a direct interpretation of model data.

The data presented in this publication does not cover all the energy conversion technologies included in the models; however, the list is slimmed down to give a concise – yet comprehensive – view of the key options of the present and future energy sector.

1.1 WHAT YOU WILL FIND IN THE CATALOGUE

Four major energy consumption and transformation sectors are considered in this study:

- *Power and district heating*, which turn conventional or renewable sources into electricity and heat (centrally produced)
- *Transport* of people and goods
- Final heat demand in *industry*, for space and process heating
- *Green fuels*, which encompass a broad spectrum of energy carriers obtained from renewable energy or conventional fuels.

This publication thus covers both transformation and end-use sectors and aims at analysing major established and novel processes at the heart of the future energy sector in the Nordics. For each macro-sector described above, several categories are defined in order to ease the comparison among technologies (Table 1).

Table 1. Matrix for cost comparisons across the different sectors analysed.

Sector	Categories			
Power and district heating	Base load and renewable generators		Peak load generators	
Transport	Passenger cars		Freight transport	
Industry	Space and Low-Temperature (LT) heating	Medium-Temperature (MT) heating	High-Temperature (HT) heating	Heavy industry
Green fuels	Liquid fuels		Gaseous fuels	

Cost indicators highlight the split among cost determinants, e.g. investment, O&M, fuel and environmental components. This is not only to illustrate the impact of each on the overall cost, but also to gauge the impact of specific assumptions in the calculations. For instance, fuel and commodity prices might follow different trends or assume a specific value conditional on for example the location.

2 Power and District Heating

2.1 BACKGROUND AND TRENDS

In the Nordic countries, the power and district heating sectors have sped up their decarbonization efforts in the past years. The share of electricity consumption covered by renewable energy has reached an aggregate 73% in 2018 (Figure 1), with variable renewable energy (VRE) capacity quadrupling from 4.8 GW to 18.8 GW in ten years (Figure 2).

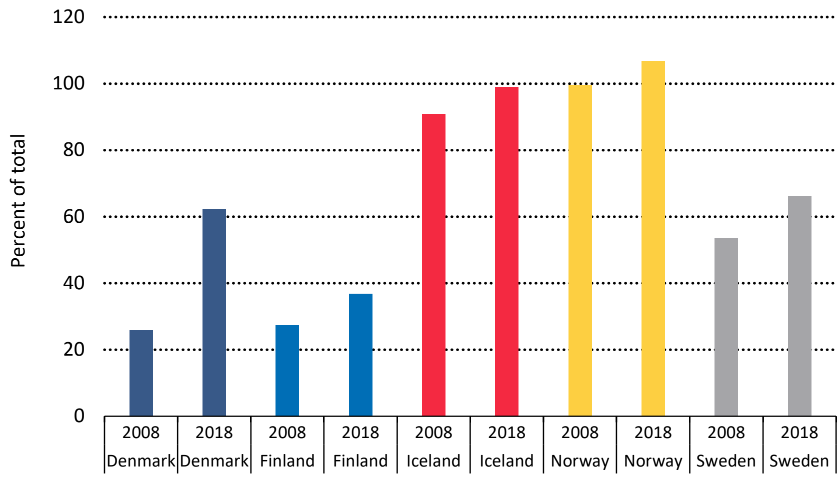

Figure 1. Share of electricity consumption covered by renewables (2008-2018). Source: (Nordic Energy Research, Ea Energy Analyses, 2020).

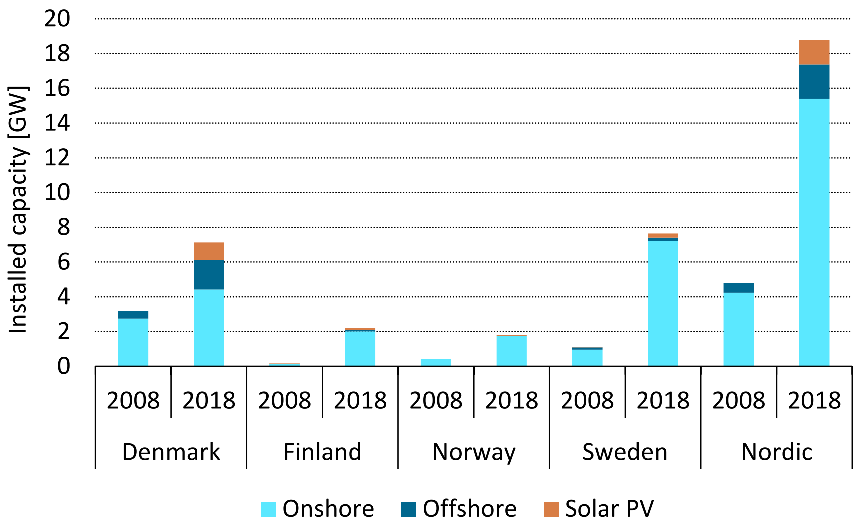

Figure 2. Evolution of variable renewable energy capacity in the Nordic countries (2008-2018). Source: (Nordic Energy Research, Ea Energy Analyses, 2020).

With 226 TWh in 2018, hydropower contributed to more than half of the electricity generation in the Nordics, while wind and biomass settled at 40 TWh and 25 TWh respectively (Nordic Energy Research, Ea Energy Analyses, 2020). Hydropower has a pivotal role in balancing the Nordic system, with both large reservoirs and pumped-hydro plants. The flexibility provided by hydro stations is essential as the penetration of VRE grows.

The Nordic region has a significant potential for clean energy deployment, with a rather diversified set of renewable energy resources. Generation from wind and biomass combined has grown steadily over the past years and solar PV is also spreading, driven by falling prices of solar modules. Despite the limited solar resource, the business case of PV is attractive already today.

Nuclear energy contributed to the generation mix with 88 TWh in 2018. This made it the second largest supplier of electricity in the region, accounting for over 20% of the gross demand. Sweden and Finland are the only countries to host nuclear power plants. In both countries nuclear and hydro are major contributors to the gross electricity supply. Bioenergy has grown steadily in Finland and ultimately topped generation from hydropower plants in 2018. Nonetheless, nuclear energy in Finland still accounts for roughly bioenergy and hydro combined. To reach carbon neutrality goals, Finland plans to phase out coal power by 2029 and integrate two new reactors in the nuclear fleet.

Geothermal energy also plays a role the Nordic energy mix, although almost only in Iceland, where it is employed for both electricity and heat production. The interest in using geothermal energy for district heating production is increasing in Denmark, Sweden and Finland.

District heating has traditionally been produced mainly at medium or large combined heat and power plants. The main fuels used are biomass, municipal solid waste, coal and natural gas (Figure 3). In Sweden heat pumps have played an important role since the 1980's. Recently heat pumps are gaining momentum in other Nordic countries as well, as a means to reduce fuel consumption and CO2 emissions and to allow an efficient integration of wind and solar power in the electricity grid. Heat pumps and electric boilers hold a significant potential to accelerate the decarbonization of the sector and free up biomass for other purposes. These two technologies can both be integrated into large district heating grids and installed in decentralized contexts.

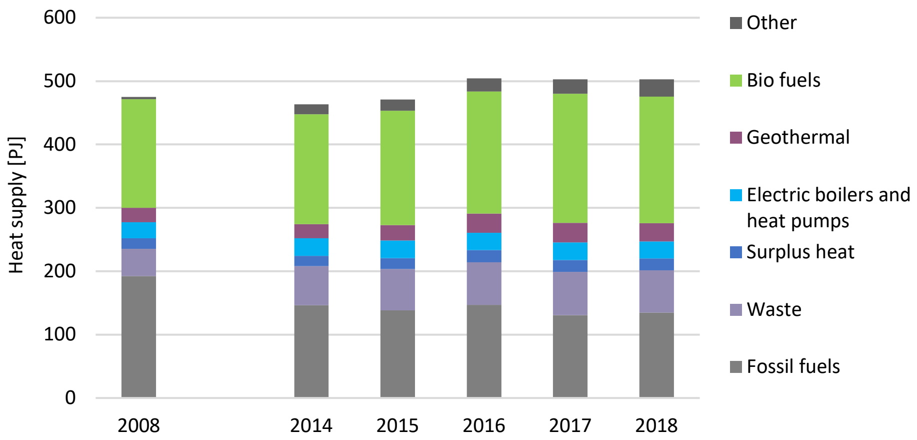

Figure 3. District heating supply by fuel in the Nordic countries (historical data). Source: (Nordic Energy Research, Ea Energy Analyses, 2020).

2.2 ASSUMPTIONS ON TECHNOLOGY DATA

For the purpose of this study, power and heat technologies are subdivided into:

- *Base load suppliers and renewable energy generators*, characterized by relatively high full load hours or low marginal costs of generation.
- *Peak load suppliers*, that is conventional power plants with medium-to-low full load hours, that have relatively high operating cost and therefore only operate when power prices are high.

Table 2 presents the full list of technologies considered in this report.

Table 2. Power and district heat technologies.

Base load and renewable generators	Peak load
Coal CHP plant	Condensing coal plant
Combined cycle CHP plant	Open-cycle gas turbine
Biomass CHP plant	Open-cycle biogas turbine
Coal CHP plant with CCS	
Combined cycle CHP plant with CCS	
Biomass CHP plant with CCS	
Nuclear power plant (new built – PWR)	
Nuclear power plant (refurbishment – PWR)	
Onshore wind	
Offshore wind	
Solar PV	

In the Nordic countries, thermal power plants serving base load purposes are mainly of the combined heat and power (CHP) type, with the exception of nuclear reactors. The reason is the widespread district heating infrastructure. Over the years, CHP units have been designed to operate over wide, dynamic ranges; this way the production of electricity and heat can be adjusted to follow demand patterns and to optimize market participation. On the other hand, peak load suppliers are typically condensing units supplying electricity only.

One of the challenges associated with a large penetration of renewable energy technologies is the progressive phase-out of dispatchable power. For the purpose of decarbonization, the main option to mitigate emissions from combustion in conventional thermal plants has been to switch from fossil fuels to biomass. Another option which is gaining attention is the installation of carbon capture and storage (CCS) facilities. If applied on power plants using biomass, a net reduction in CO2 emissions can be achieved.

At present, the most common CCS concept involves the sequestration of CO_2 from the flue gases (post-combustion capture, treated in the following). There is substantial industry experience with this technology, as it has been employed for decades in industrial applications, in particular in natural gas processing. Other capture techniques such as pre-combustion capture or oxy-fuel combustion are at a lower technology readiness level (TRL) and, at present, appear less attractive from an economic perspective. Increasing deployment of electrolyzers may however yield a boost for oxy-fuel plants which can take advantage of the surplus oxygen from the water splitting process.

An example of a CCS pilot project in the Nordics is the Värtan CHP plant in Stockholm, which runs on biomass (IEA, 2020). The CO_2 is sequestered and then compressed and transported in liquid form to an underground rock formation, where it is stored. In addition to biomass units, CCS can be applied to other fossil fuel and waste-to-heat plants.

Renewable generators

The operation and annual yield of onshore and offshore wind turbines are very dependent on the wind conditions or, in other terms, on the potential full load hours. Wind speeds change not only with the geographical location but also with height above ground and the turbine design influences the wind power captured by the blades. Recent years have displayed a growing diversification in turbine design for low-, medium- and high- wind sites: units with bigger rotors (lower specific power) and taller towers are installed in low-wind sites, allowing higher full load hours, even if at the expense of a higher initial investment. Full load hours are also expected to increase in the future as a consequence of higher conversion efficiencies due to improved blade design, more sophisticated pitch systems, smaller losses in mechanical-electrical energy conversion systems and in the power electronics.

The reference offshore turbine is assumed to have characteristics in-between a far-offshore and a near-shore turbine. The biggest developments in offshore capacity are foreseen to take place at intermediate distances from shore. Assumptions for on- and offshore wind full load hours are reported in Table 5. A more detailed discussion is provided in the Appendix (Section 7.1).

Even if endowed with a low solar resource, the decline in module prices has made PV an increasingly attractive option in the Nordics. Denmark has a better, more widespread solar resource than the other Nordic countries, but annual productions topping 1000 full load hours can be achieved also in selected locations in Sweden. Moreover, the deployment of solar PV in the Nordics might take advantage of the steep decline in storage costs (especially batteries); Li-Ion batteries have displayed learning rates comparable to those of wind and solar PV. Assumptions regarding the full load hours of solar PV are reported in Table 5, reflecting irradiation levels typical of sites with the greatest potential in the region.

Other renewable technologies such as hydropower and geothermal energy are not treated in this report. Further hydropower development faces considerable challenges due to its environmental impacts, while the development of geothermal power plants is very specific to Iceland. As of 2019, 754 MW_e geothermal power capacity was installed in Iceland, with a modest 5 MW_e capacity expansion in the same year (EGEC, 2020).

Base load generators

Thermal cogeneration plants (coal, combined cycle, biomass) considered in this catalogue are assumed to be of the extraction type. They feature their C_b and C_v characteristics, which define a dynamic range over which the plant can regulate its heat and power outputs. The plant's efficiency in full-condensing mode is linked to the efficiency in any other CHP operational setup through the C_b and C_v coefficients. Biomass units are included in this category for the role they play in the Nordic power sector.

Nuclear power is also treated in this report. The expansion of the nuclear power fleet is a controversial matter in the Nordic countries, with diverse national stances. Denmark, Iceland and Norway holds no nuclear power today and do not consider it as a future option. In Sweden, a number of the oldest reactors have been shut down and the discussion revolves mainly around whether the remaining units should be upgraded, maintained at current capacity or closed down before the end of their technical lifetime. In Finland, where a new reactor (Olkiluoto 3, 1600 MW) is expected to come online in 2021, the government has approved the construction of two additional units. Sweden and Finland have a mix of pressurized water reactors (PWRs) and boiling water reactors (BWRs) in operation. This study considers both new nuclear power plants and the refurbishment of existing units in the LCOE calculations.

Peak load generators

Peak load plants typically run in condensing mode, i.e. with no heat production. Among other functions, they support the system in case of high system loads and unavailability of conventional and renewable power plants. High marginal costs of generation are also a result of frequent start-up and ramping, as these plants are generally idle. Yearly operations equivalent to 1000 full load hours are assumed for these units.

Table 3 shows the main techno-economic parameters for selected power and heat technologies included in the models. The main source for the technology data reported here is (Danish Energy Agency and Energinet, 2020). Additional values for the year 2020 are given in the Appendix.

Table 3. Main techno-economic parameters of power generation technologies (in 2030 and 2050).

Technology	Year	Typical plant size [MW]	CHP	Electric Efficiency [%]	Total efficiency [%]	Investment cost [MEUR/MW]	Fixed O&M [1000EUR/MW]	Variable O&M [EUR/MWh]
RENEWABLE GENERATORS								
Onshore wind[1]	2030	100	No	-[2]	-[2]	1.28	19.26	1.75
	2050	100				1.13	17.36	1.54
Offshore wind	2030	500				1.69	37.05	2.74
	2050	500				1.43	32.60	2.41
Solar PV	2030	20				0.31	5.92	-
	2050	20				0.24	5.01	-
BASE LOAD								
Coal CHP plant	2030	500	Yes	50	90	1.86	30.36	2.84
	2050	500		53	89	1.78	29.11	2.72
Combined cycle CHP plant	2030	500		58	80	0.84	28.18	4.25
	2050	500		60	81	0.80	26.23	4.03
Biomass CHP plant (wood chips)	2030	500		41	102[3]	2.45[4]	66.50	2.60
	2050	500		40	104[3]	2.33[4]	62.50	2.68
Coal CHP plant with CCS	2030	500		37	69	4.02	97.78	6.78
	2050	500		41	71	3.29	74.87	6.09
Combined cycle CHP plant with CCS	2030	500		43	78	2.29	42.37	2.75
	2050	500		46	79	2.02	32.61	2.55
Biomass CHP plant with CCS (wood chips)	2030	500		30	65	5.38[4]	175.83	5.62
	2050	500		32	73	4.27[4]	136.30	5.23
Nuclear power plant (PWR)	2030	1000		35	-	4.5	-	10.7
	2050	1000						
Nuclear power plant (PWR) - refurbishment[5]	2030	1000		35	-	0.93	83.00	
	2050	1000		35	-	0.93	83.00	
PEAK LOAD								
Coal power plant – condensing	2030	100	No	50		1.69	26.05	2.44
	2050	100		53		1.62	24.98	2.34
Open-cycle gas/biogas turbine	2030	50		40		0.51	15.92	3.60
	2050	50		42		0.47	15.34	3.41

[1] Design and investment costs depend on the wind resource at the location. The Appendix provides further details on the reference turbine chosen.
[2] From an energy systems modelling perspective, electricity production from renewable generators is defined by the full load hours.
[3] Efficiencies higher than 100% are achieved because the lower heating value is considered and flue gas condensation is common practice in selected plant types (e.g. biomass).
[4] Smaller biomass CHP plants would typically have higher specific investment cost.
[5] The refurbishment cost for BWRs can be considered to be 25% lower than that of PWRs. For more details, see (Energiforsk, 2021).

Uncertainty ranges applied to the investment cost figures are shown in Table 4; uncertainty on O&M is not considered. The source is the Danish Energy Agency's technology catalogue for generation and district heat. When uncertainty estimates from the Danish Energy Agency are not available, other internal estimates or alternatively a ± 25% interval are assumed.

Table 4. Investment cost uncertainty ranges for power and heat technologies [MEUR/MW].

Technology	Year	Uncertainty (down)	Uncertainty (up)
Onshore wind	2030	0.88	1.38
	2050	0.94	1.25
Offshore wind	2030	1.21	2.17
	2050	1.07	1.79
Solar PV	2030	0.22	0.41
	2050	0.18	0.30
Coal CHP plant	2030	1.40	2.33
	2050	1.34	2.23
Combined cycle CHP plant	2030	0.79	1.21
	2050	0.73	1.15
Biomass CHP plant	2030	2.39	3.26
	2050	2.31	3.46
Coal CHP plant with CCS	2030	2.98	5.06
	2050	2.47	4.12
Combined cycle CHP plant with CCS	2030	1.71	2.87
	2050	1.51	2.52
Biomass CHP plant with CCS	2030	4.02	6.74
	2050	3.20	5.33
Nuclear power plant (new built)	2030	3.00	6.50
	2050	3.00	6.50
Nuclear power plant (refurb.)	2030	0.74	1.12
	2050	0.74	1.12
Coal power plant - condensing	2030	1.27	2.11
	2050	1.22	2.03
Open-cycle gas/biogas turbine	2030	0.40	0.92
	2050	0.37	0.89

2.3 LCOE METHODOLOGY

Technologies in this Chapter are compared through their Levelized Cost of Electricity (LCOE). LCOE is a synthetic measure showing the discounted lifetime cost of electricity production from a generation asset, defined as follows:

$$LCOE = \frac{I + \sum \frac{O + Fuel + Env - H}{(1+r)^y}}{\sum \frac{W}{(1+r)^y}}$$

where each parameter has the meaning specified below.

I: capital investment

O: operation and maintenance expenditures

Fuel: fuel cost

Env: environmental costs

W: power production

H: heat revenue

r: discount rate

y: year of operation

Operation and maintenance (O&M) costs are assumed to be equal throughout the unit's lifetime. Heat revenues are subtracted from the negative cash flows in CHP units. Environmental costs include CO_2, SO_x, NO_x and particulate matter emissions.

LCOE calculations ground in the following assumptions:

- Cash flows are calculated for an economic lifetime of 20 years[6]
- The socio-economic discount rate is set to 5% (in real terms)
- Dismantling and disposal costs are disregarded.

[6] Nuclear power plants constitute an exception (lifetime is 60 years for new-built plants).

The LCOE is widely used to compare the economic attractiveness of different generation technologies; however, the approach presented in this study entails a number of limitations, which should be taken into account for more accurate assessments:

- The availability of renewable resources (e.g. solar irradiation and wind speed) varies among sites and therefore countries. A single LCOE result cannot capture these differences. As a result, country- or location-specific calculations should account for different conditions.
- In reality, cash flows change from year to year based on operations and commodity prices (in terms of both costs and revenues). For instance, heat revenues are considered to be constant over the plant's lifetime.

Full load hours impact LCOE calculations as well. As the Danish Technology Catalogue reports

> *The number of annual full load hours is used to express the utilization rate of the power plant. The assumptions regarding full load hours have a high influence on the LCoE due to contributions from fixed costs such as capital cost and fixed operation and maintenance cost. Renewables like wind power and solar power have very low marginal costs. Therefore, their annual full load hours are almost exclusively dependent on the available renewable energy resource and the choice of technology. For thermal power plants the number of full load hours depends on their function in the electricity market, i.e. if they operate as base load, mid-load or peak load. Nuclear power plants also have low marginal cost and would therefore normally operate as base load with a high number of full load hours.*

Assumptions for the full load hours of all generators are summarized in Table 5. Full load hours (FLH) of base load technologies can span over wide ranges, depending on e.g. the plant design and the system's needs. A uniform value of 6000 FLH was chosen for base load technologies, which corresponds to a 68% capacity factor; nuclear reactors constitute an exception, with 7500 FLH (Energiforsk, 2021). Onshore and offshore wind are assumed to have capacity factors of 40% and 50%, respectively. For the sake of LCOE calculations, these values are kept equal over the investigated horizon. In reality, full load hours of renewable technologies are bound to increase following on improved design, manufacturing and material choices.

Table 5. Full load hours for LCOE calculations.

	Base load (nuclear excluded)	Nuclear power plant	Onshore wind	Offshore wind	Solar PV	Peak load technologies
Full load hours	6000	7500	3500	4500	1000	1000

2.4 LCOE RESULTS

Base load and renewable technologies

Figure 4 shows the LCOE for the base load and renewable technologies under study (2030). The overall LCOE for CHP plants is marked with an orange dot in the plot in order to account for heat revenues.

Solar PV is projected to be the cheapest source of renewable energy despite the relatively scarce solar resource, with the LCOE estimated at 31 EUR/MWh. Electricity from wind stands between 37 and 41 EUR/MWh for onshore and offshore respectively. Both wind and solar technologies are expected to benefit from improvements in design, manufacturing, installation, and maintenance. The cost of electricity from renewable plants is utterly dependent on the full load hours at the location (see Sections 7.2 and 7.3 in the Appendix), therefore such LCOE figures are illustrative and do not reflect particular conditions in the Nordic countries.

Electricity from the sun and wind is already less costly than that generated in conventional power plants; in the coming years, renewables will have a corner on the market due to technological learning. Despite this, base load technologies are still pivotal to keep the power system in balance. Traditional, well-established power cycles fuelled by coal, natural gas and biomass display total costs of generation between 80-220 EUR/MWh (including heat revenues), of which the environmental component holds a remarkable share. Generation from natural gas and biomass is also very sensitive to fuel prices. The LCOE for biomass power plants also includes the environmental cost of emitting CO_2 (dashed area). This is to show the difference in LCOE between the cases with and without CCS[7]. Finally, newly-built nuclear power plants exhibit an LCOE of

[7] The difference in LCOE represents the socio-economic gain of installing CCS no matter how biomass plants are treated.

49 EUR/MWh (60-year lifetime), while refurbishments extending the lifetime by 20 years come at a cost of 27 EUR/MWh.

Figure 4 shows also that abating emissions from selected conventional power plants comes at lower socio-economic cost already in 2030. Equipping coal and biomass generators with CCS penalizes the cycle net efficiency and increases the need for maintenance but mitigates the impact on the environment. CCS is less attractive for biomass plants then for coal and gas cycles because of the higher fuel price. The socio-economic cost of electricity produced in coal and gas plants is down 14-18 EUR/MWh with the installation of CCS. These considerations hold for new power plants, but carbon capture equipment can also be used to retrofit existing power plants, especially if the unit is of relatively recent construction.

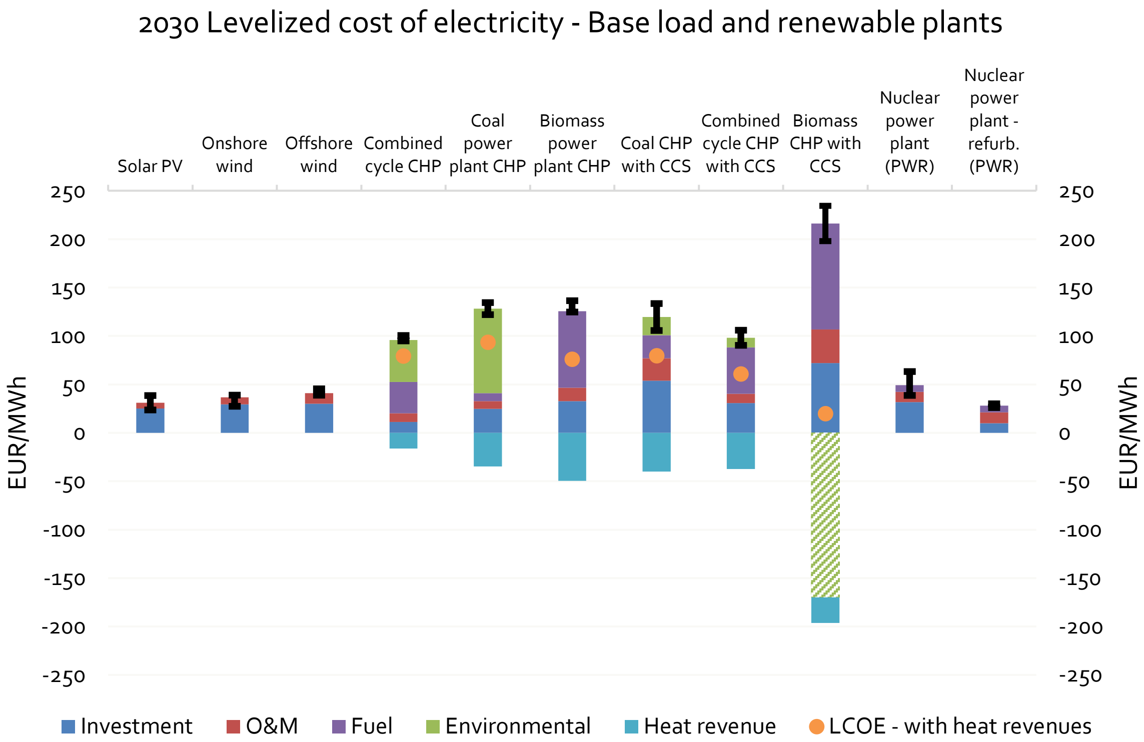

Figure 4. LCOE for base load and renewable technologies (2030). Uncertainty ranges apply only to the investment cost.

In 2050, electricity generation from renewables will experience further cost drops, with solar PV down to around 24 EUR/MWh and wind to 32-35 EUR/MWh, for onshore and offshore respectively. The location of wind farms further offshore might make offshore wind even more competitive.

On the contrary, power produced in conventional power plants is set to become more expensive, due to an expected surge in CO_2 prices. Fossil fuel prices are expected to be roughly stable over the considered horizon (Table A.1). The modest decrease in investment and maintenance expenditures has little effect on the aggregate LCOE. Nuclear power costs (PWR reactors) are invariant over the investigated horizon.

The cost of equipping power plants with CCS decreases with time, making CCS technologies more attractive. In 2050, a combined cycle with post-combustion capture generates electricity for 57 EUR/MWh, assuming base load operations. However, the abatement cost per unit CO_2 removed is higher than the other CCS technologies, as CO_2 concentration is lower in the flue gas (Table 6) [8].

Table 6. Calculated CO2 abatement costs in 2050.

	Coal CHP plant	Combined cycle CHP plant	Biomass CHP plant
CO_2 abatement cost [EUR/t]	74	100	55

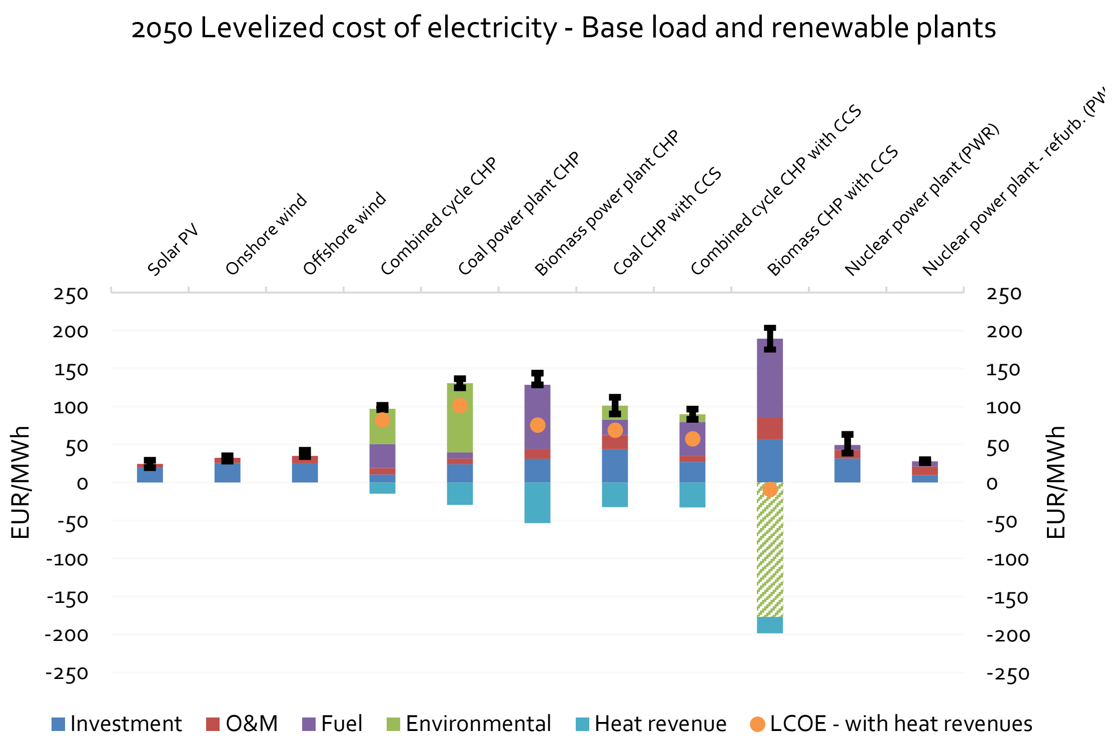

Figure 5. LCOE for base load technologies (2050). Uncertainty ranges apply only to the investment cost.

[8] Carbon sequestration has an efficiency between 85-90% nowadays with marketed technologies. Efficiency can top 95%, but the CCS equipment would be markedly costlier.

LCOE results are also summarized in Table 7.

Table 7. LCOE figures for power and heat technologies. Values include heat revenues for CHP plants.

	Solar PV	Onshore wind	Offshore wind	Biomass CHP plant	Coal CHP plant	Combined cycle CHP plant	Nuclear power plant
2030	31.1	36.5	41.1	221.1 220.5 (with CCS)	93.6 79.7 (with CCS)	79.5 61.0 (with CCS)	49.20 (new bult)
2050	24.4	32.4	35.2	244.9 199.7 (with CCS)	101.2 68.7 (with CCS)	82.1 57.2 (with CCS)	28.03 (refurbishment)

Peak load technologies

Figure 6 shows the LCOE for peak load technologies (2030). Natural gas turbines are the lowest-cost option to supply peak power in 2030, with a generation cost of 160 EUR/MWh. The same engine running on biogas is a more expensive option (~275 EUR/MWh), due to the higher fuel cost (see Chapter 6). Small coal power plants are not an attractive solution for back-up purposes, as the environmental load and high capital costs make the LCOE top 275 EUR/MWh.

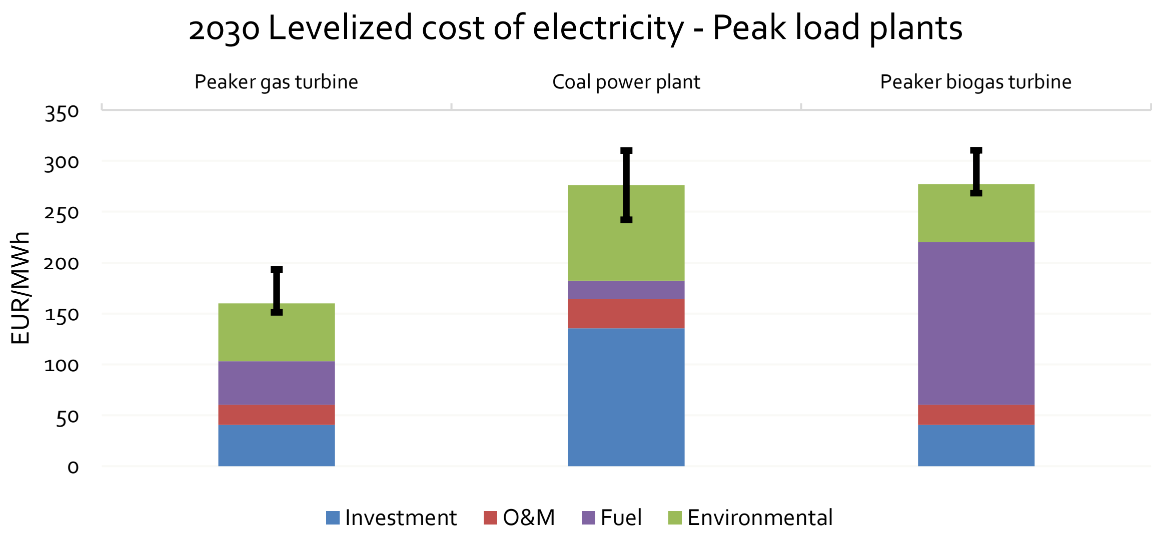

Figure 6. LCOE for peak load technologies (2030). Uncertainty ranges apply only to the investment cost.

Since these technologies are already mature, no significant cost reduction is expected further down the line. On the contrary, the projected increase in CO_2

prices will make peak load generation slightly costlier, with biogas less affected due to a projected decrease in fuel price (Section 6.4).

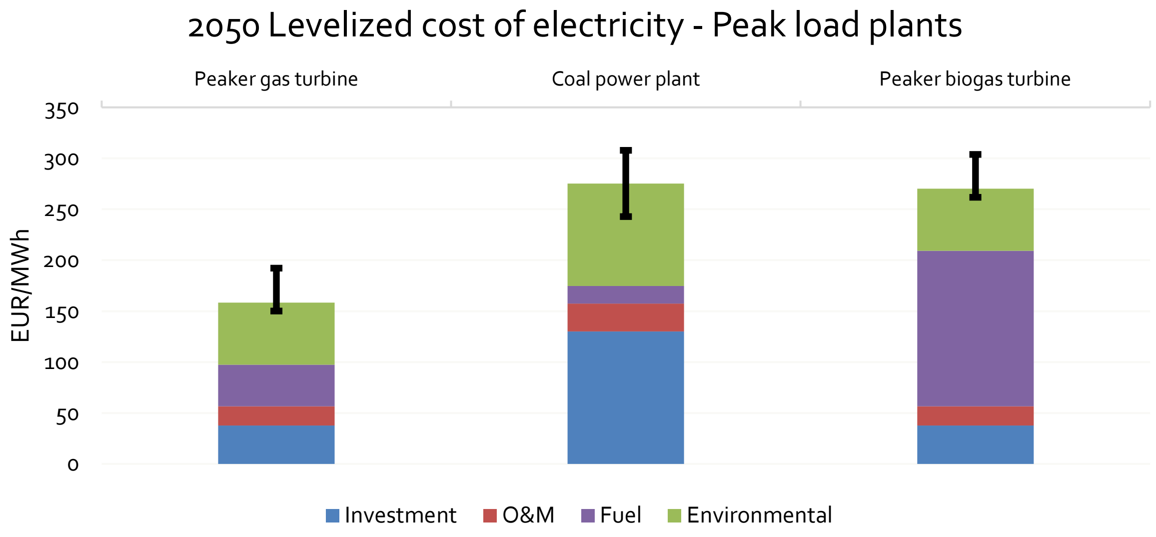

Figure 7. LCOE for peak load technologies (2050). Uncertainty ranges apply only to the investment cost.

3 Transport

3.1 BACKGROUND AND TRENDS

In 2018, the transport sector accounted for between 16-28% of the gross final energy demand in the Nordic countries[9]. The share of renewables in the final energy consumption reached 30% in Sweden, whereas it stagnated at roughly 7% in Denmark, the other countries lying in-between. Even if this share has generally grown in the past years, it has done so at a rather slow pace. The use of biofuels has been the major reason for the uptake of renewables in the sector, yet at the end of 2018 biofuels made up only 12% of the sector's final energy use; the largest contribution came from biodiesel (Figure 8).

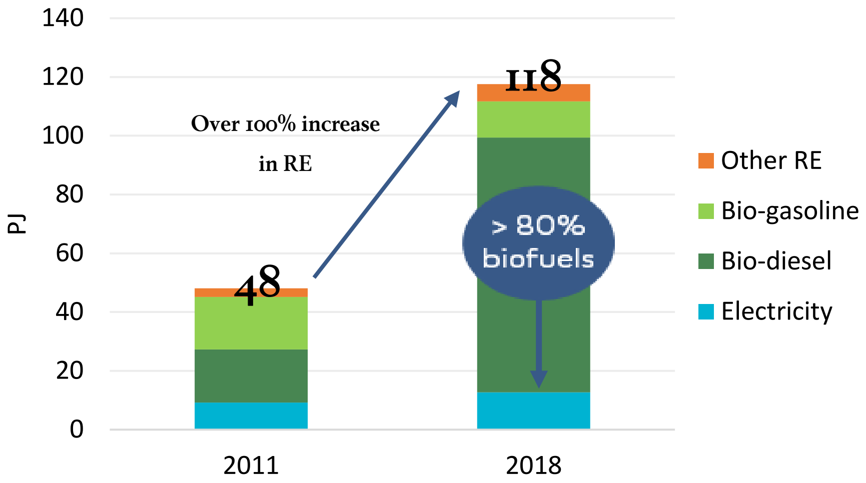

Figure 8. Renewable energy consumtpion in the transport sector in the Nordics (2011-2018). Source: (Nordic Energy Research, Ea Energy Analyses, 2020).

Road transport remains the sub-sector with the highest energy consumption, demanding around 90% of the transport sector's final energy demand. The share of cars in inland passenger transport exceeded 80% in 2018 (Nordic Energy Research, Ea Energy Analyses, 2020) and internal combustion engines (ICEs) are still the dominant technology. At the end of 2018, more than 90% of the passenger cars fleet relied on gasoline and diesel ICEs (where biofuel is an option), with peaks of 98 and 99% in Denmark and Finland respectively (European Automobile Manufacturers Association, 2019).

[9] Source: Eurostat's SHARES.

Recent years have shown a steady increase in electric vehicles (EVs) sales, particularly in Norway, where EVs accounted for more than half of the new car registrations in 2019 (Figure 9) and the share of electric cars (all types: plug-in, hybrid and full-electric) surpassed 10% at the end of 2018. The other Nordic countries are lagging somewhat behind, as the electric car fleet makes up only between 0.5 and 3% of all passenger vehicles (European Automobile Manufacturers Association, 2019).

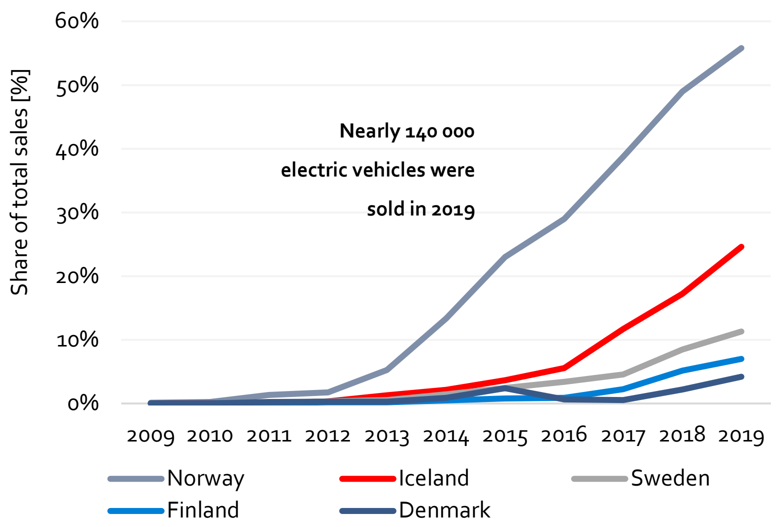

Figure 9. Battery and plug-in hybrid electric vehicles share of new passenger vehicle sales (by country). Source: (Nordic Energy Research, Ea Energy Analyses, 2020).

The penetration of low carbon carriers is not uniform for passenger and freight transport, the latter being harder to decarbonize. Even though the sales of passenger EVs is picking up, many hindrances are yet to be overcome in haulage. Challenges are especially related to electric solutions for long distances, where traditional internal combustion engines stay more competitive. In fact, electric options for long haul would require very large and heavy batteries, which also reduce payload capacity. Solutions can come either from a further decline in battery costs or from the commercialization of storage with higher energy densities. Nonetheless, electrification still is limited even in the light commercial vehicles segment. In any of the Nordic countries, EVs make up less than 2% of the stock.

As electrification will not be a feasible option for the decarbonization of certain transport segments (at least, not in the very short term), alternative fuels (biofuels and hydrogen) may be needed. This catalogue focuses on options to decarbonize medium-size passenger cars and trucks for freight transport through change of drivetrain. However, it should be acknowledged that substantial CO_2 emission reductions might also materialize on the back of:

- Avoid/Shift practices in favour of non-motorized transport modes
- Vehicle efficiency.

These advancements have the effect of reducing the final demand for energy. An important step towards decarbonization may come from behavioural changes, novel business models and an integrated infrastructure planning that includes a paradigmatic switch to less energy-intensive modes for both passenger transport and freight (for instance, rail).

3.2 ASSUMPTIONS ON TECHNOLOGY DATA

The broad categories considered in this study are:

- Medium-size passenger cars
- Trucks for freight transport

Transport modes within these categories make up the largest share of the final energy demand in the transport sector, as previously mentioned. Other transport categories such as railway transport, marine shipping, air transport and ferries are not considered as they constitute a minor share of the sector's energy consumption. To a large extent, decarbonization efforts in these sectors hinge on the competitiveness and deployment of green fuels, a topic treated in Section 6. Hence, progress is partly tied to the transformation of the supply sector and not entirely to the introduction of new ground-breaking transport technologies. In addition, cost comparisons are difficult to be drawn for some transport means (e.g. vehicles and trains) as infrastructure costs, which include network strengthening and expansion, are context-specific. The transport modes under study are summarized in Table 8.

Table 8. Transport technologies considered in the study.

Passenger cars	Freight transport
Gasoline car	Diesel truck
Diesel car	Natural gas truck
Natural gas car	Biogas truck
Battery electric vehicle (BEV) – 300 km range	Electric truck – 400 km range
Battery electric vehicle (BEV) – 500 km range	Electric truck – 1000 km range
Plug-in hybrid car	Fuel cell truck – 400 km range
Fuel cell cars	Fuel cell truck – 1000 km range

Transport technologies are characterized by their mode efficiency and costs. The efficiency is expressed in vehicle-km/GJ (of input fuel). Figures for the different transport modes are illustrative and they do not attempt to represent the whole car and truck fleets. Cars fuelled by a blend of conventional oil products and biofuels are assumed to have the same size and vehicle efficiency (in km/l) as their fossil counterparts. However, due to the diverse energy content of the fuels, the efficiency in vehicle-km/GJ proves different.

The main techno-economic assumptions for all transport modes considered in this report are shown in Table 9. The main data sources are the Nordic TIMES model and Ea Energy Analyses' transport models. Additional values for the year 2020 are given in the Appendix.

Table 9. Main techno-economic parameters for transport technologies.

Technology	Year	Efficiency [MJ/vehicle-km]	Investment cost [1000EUR/vehicle]	Fixed O&M [1000EUR/vehicle /year]
PASSENGER CARS				
Gasoline car	2030	1.68	14.94	700
	2050	1.43	14.94	700
Diesel car	2030	1.64	16.58	800
	2050	1.40	16.58	700
Natural gas car	2030	2.00	17.93	800
	2050	1.56	17.93	700
BEV – 300 km range	2030	0.52	16.29	420
	2050	0.45	13.95	420
BEV – 500 km range	2030	0.54	18.11	420
	2050	0.46	14.84	420
Plug-in hybrid car (gasoline+battery)	2030	0.86	16.44	700
	2050	0.64	14.62	700
Fuel cell car	2030	0.94	20.17	818
	2050	0.71	14.19	777
FREIGHT TRANSPORT				
Diesel truck	2030	11.46	110.00	10470
	2050	10.68	110.00	10470
Natural gas/biogas truck[10]	2030	13.23	143.56	11517
	2050	11.92	134.16	11517
Electric truck – 400 km range	2030	5.59	153.01	7000
	2050	5.09	121.04	7000
Electric truck – 1000 km range	2030	6.13	240.28	7700
	2050	5.35	152.31	7700
Fuel cell truck – 400 km range	2030	9.24	129.91	10989
	2050	7.75	107.50	9249
Fuel cell truck – 1000 km range	2030	9.28	150.44	12026
	2050	7.77	113.32	10155

[10] A biogas truck is the same as a natural gas truck, but uses upgraded biogas as a fuel in lieu of its fossil counterpart.

Table 10. Investment cost uncertainty ranges for transport technologies.

Technology	Year	Uncertainty (down)	Uncertainty (up)
Gasoline car	2030	14.19	15.69
	2050	14.19	15.69
Diesel car	2030	15.75	17.41
	2050	15.75	17.41
Natural gas car	2030	15.24	20.62
	2050	15.24	20.62
BEV – 300 km range	2030	13.03	19.55
	2050	11.16	16.74
BEV – 500 km range	2030	14.49	21.73
	2050	11.87	17.81
Plug-in hybrid car (gasoline+battery)	2030	13.15	19.73
	2050	11.69	17.54
Fuel cell car	2030	15.13	25.21
	2050	10.64	17.74
Diesel truck	2030	82.50	137.50
	2050	82.50	137.50
Natural gas/biogas truck	2030	118.22	159.95
	2050	114.04	154.29
Full electric truck – 400 km range	2030	122.41	183.62
	2050	96.83	145.25
Full electric truck – 1000 km range	2030	192.23	288.34
	2050	121.85	182.77
Fuel cell truck – 400 km range	2030	97.43	162.38
	2050	80.63	134.38
Fuel cell truck – 1000 km range	2030	112.83	188.05
	2050	84.99	141.65

Passenger cars calculations

In practice, consumers rely on different sizes and types of passenger vehicles given their needs and preferences. For example, diesel vehicles are on average much larger and are driven more km per year than gasoline vehicles. For the purposes of the current analysis however, to enable a comparison of passenger vehicles across drivetrains, a standard small/medium sized vehicle was generated for each drivetrain type. The 2020 reference vehicle is gasoline powered with a weight in running order of 1,370 kg (1,420 kg with cargo), assumed engine and drivetrain efficiency of 23%, resulting in a calculated energy use of 1.95 MJ/km, and an upfront cost of EUR 14 940. Anticipated vehicle size, efficiency and price developments were then implemented towards 2050. For diesel, natural gas, plug-in hybrids, and fuel cell vehicles, corresponding weight and drivetrain efficiencies and resulting vehicle energy use were implemented (i.e., a diesel engine weighs more than a gasoline engine, which therefore requires more energy to propel the vehicle, but a diesel engine has a higher efficiency). Future price developments were largely based on expected production volumes, as well as anticipated technology development, the latter of which was most relevant for the fuel cell vehicle.

For the 300 and 500 km range EVs the point of departure for price and weight was a gasoline vehicle without the internal combustion engine and large multi-speed transmission unit. To this was added enough battery capacity to achieve a range of 300 and 500 km, respectively. These battery capacity figures fall over time as the energy density of batteries improve (i.e., more energy per kg results in less kWh being required as the weight of the battery is reduced). Falling battery sizes, coupled with assumed falling battery costs per kWh, result in the battery cost for EVs with fixed 300 and 500 km ranges to fall significantly towards 2030 and 2050. The battery specific assumptions utilised for the EV and plug-in hybrid vehicle calculations are displayed in Table 11.

Table 11. Cost and energy density assumptions for battery development.

Battery element	2020	2030	2050
Cost (EUR/kWh)	135	55	33
Density (Wh/kg)	240	400	532

Trucks calculations

For the freight transport calculations, a similar methodology to that of passenger vehicles was employed. I.e., the point of departure was the cost and energy demand for a traditional diesel lorry and assumed developments in drivetrain efficiencies and production volumes for the diesel and gas versions were implemented towards 2030 and 2050. For electric and fuel cell trucks, versions with 400 km and 1,000 km driving ranges were modelled, with primary inputs including a recently released Transport and Environment analysis (Transport and Environment, 2020), which forecasted the development in electric and hydrogen fuelled trucks for both regional delivery (approximately 400 km) and long-haul (approximately 1,000 km) sized vehicles towards 2030. These inputs were combined with the battery assumptions displayed in Table 9 and assumptions in technology and price developments to arrive at outputs for 2050.

3.3 LCOT METHODOLOGY

The comparison among technologies is drawn on the Levelized Cost of Transport (LCOT), which is defined as follows:

$$LCOT = \frac{I + \sum \frac{O + Fuel + Env}{(1+r)^y}}{\sum \frac{D}{(1+r)^y}}$$

where D is the distance travelled per year [km]. The other parameters are the same as in the LCOE definition (see Section 3.3).

LCOT calculations ground in the following assumptions:

- Cash flows are calculated for an economic lifetime of 10 years for cars and 8 years for trucks.
- The socio-economic discount rate is set to 5%.
- Disposal costs are disregarded.

The transport sector is undergoing significant transformations in terms of technology availability and in the way these technologies are used. The average age of road transport modes is increasing at both the EU and Nordic level and yearly usage is very country-dependent, one reason being national levies on vehicle ownership. Mileage is an important parameter affecting the LCOT and driving distances vary significantly across the Nordic countries. For example, in 2018 the average gasoline and diesel car in Denmark drove around 5000 km more than in Sweden (European Automobile Manufacturers Association, 2019). Assumptions for the mileage of different transportation modes are reported in Table 12 and Table 13; the mileage for a specific transport mode does not vary over the investigated time horizon.

Table 12. Mileage assumptions for passenger cars.

PASSENGER CARS	Gasoline car	Diesel car	Natural gas car	Battery electric vehicle	Plug-in hybrid car	Fuel cell car
Yearly mileage [km]	16 000	16 000	16 000	16 000	16 000	16 000

Table 13. Mileage assumptions for freight transport.

FREIGHT TRANSPORT	Diesel truck	Natural gas truck	Full electric truck	Fuel cell truck
Yearly mileage [km]	100 000	100 000	100 000 – (400 km range) 100 000 (1000 km range)	100 000 – (400 km range) 100 000 (1000 km range)

3.4 LCOT RESULTS

Passenger cars

Figure 10 shows the LCOT for passenger cars in 2030. The levelized cost of driving one kilometre ranges between 0.17-0.24 EUR per vehicle, with battery electric vehicles (BEVs) being the cheapest alternative. BEVs result to be the best option also when equipped with larger batteries (500 km range), which enhance autonomy; overall, BEVs display relatively low investment and O&M cost components. Traditional internal combustion engines' (ICEs) LCOT lies between 0.20-0.22 EUR/km per vehicle, with gasoline cars being the cheapest option. Plug-in hybrid cars display an LCOT which is lower than traditional ICEs, albeit higher than that of full-electric vehicles, while fuel cell cars are expected to be less competitive (LCOT = 0.24 EUR/km per vehicle).

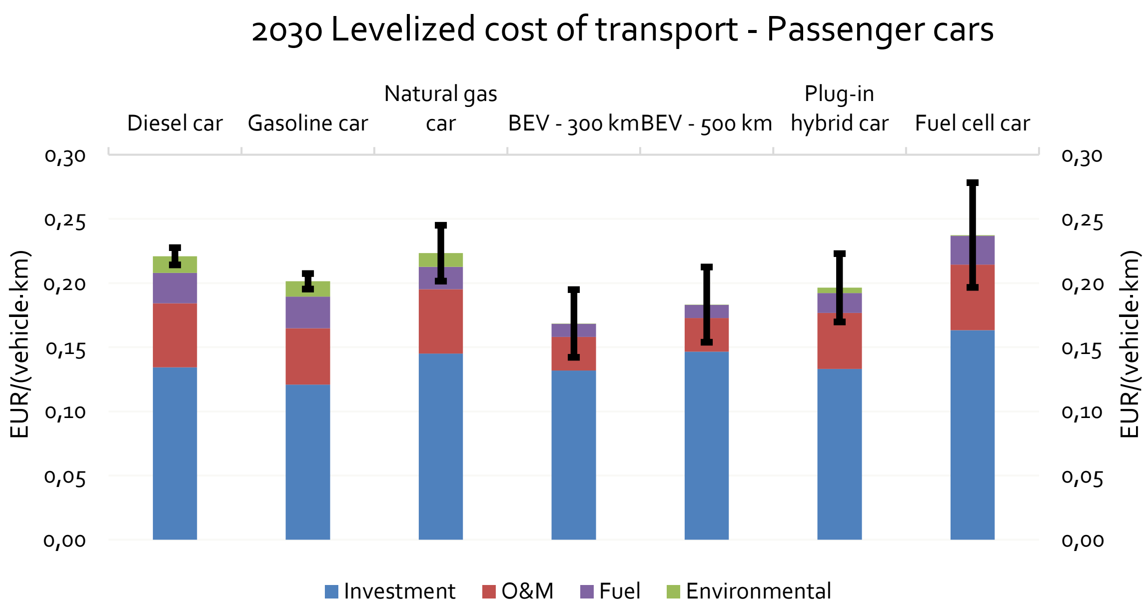

Figure 10. LCOT for passenger cars (2030). Uncertainty ranges apply only to the investment costs.

ICEs are a mature technology and moderate progress is anticipated. There is a considerable uncertainty in the cost development of fuel cell cars, whose main drivers are R&D investments and the future market share. The competitiveness with other green alternatives (BEVs) and the emphasis of policies on hydrogen for light-duty vehicles will determine the market uptake of vehicles running on fuel cells (and so the technology's cost reduction). The LCOT of fuel cell cars and plug-in hybrids drops to 0.18 EUR/km-vehicle in 2050 (Figure 11), while BEVs' LCOT is found to be around 0.15 EUR/km-vehicle, regardless of the vehicle range.

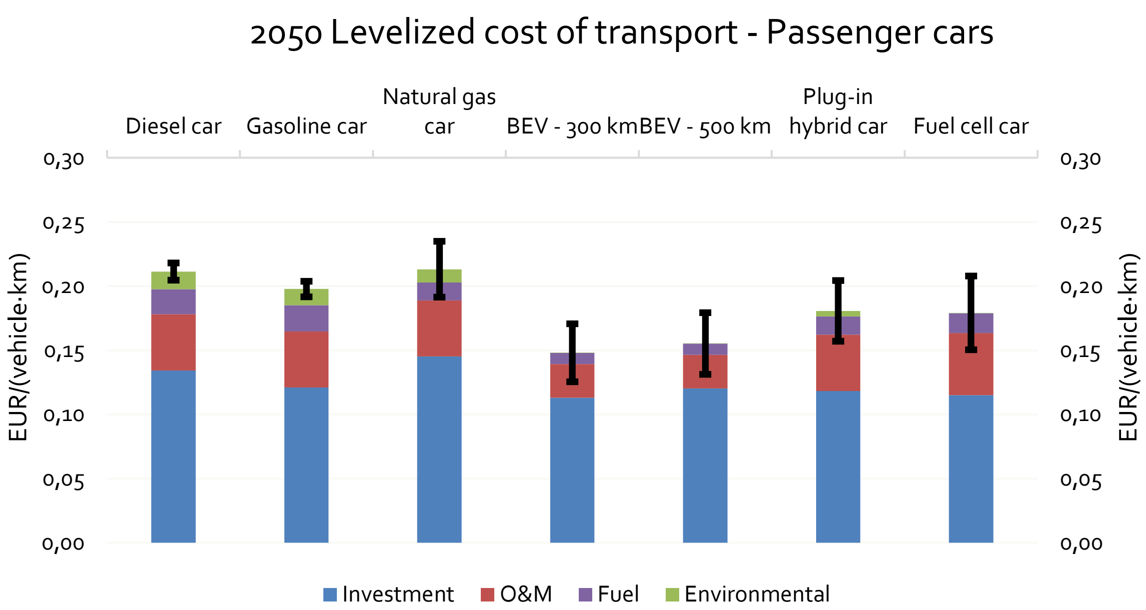

Figure 11. LCOT for passenger cars (2050). Uncertainty ranges apply only to the investment costs.

Freight transport

Figure 12 shows the LCOT for freight transport in 2030. Diesel trucks, which make up the far largest share of trucks today, display an LCOT of 0.45 EUR/km-vehicle, along with natural gas trucks. This figure is higher than that of short-range electric lorries, whose levelized cost is 0.42 EUR/km-vehicle; increasing this mode's range from 400 to 1000km cause rises the LCOT to 0.57 EUR/km-vehicle. Electric trucks designed to run longer distances are equipped with larger batteries, which increases costs consistently in the short-term. A smaller gap exists between short- and long-range fuel cell trucks, as more modest additional investment and maintenance costs are required to extend the driving range. Fuel cell trucks for short distances display an LCOT of 0.54 EUR/km-vehicle, while the cost is 0.04 EUR/km-vehicle higher for long-range lorries of the same type.

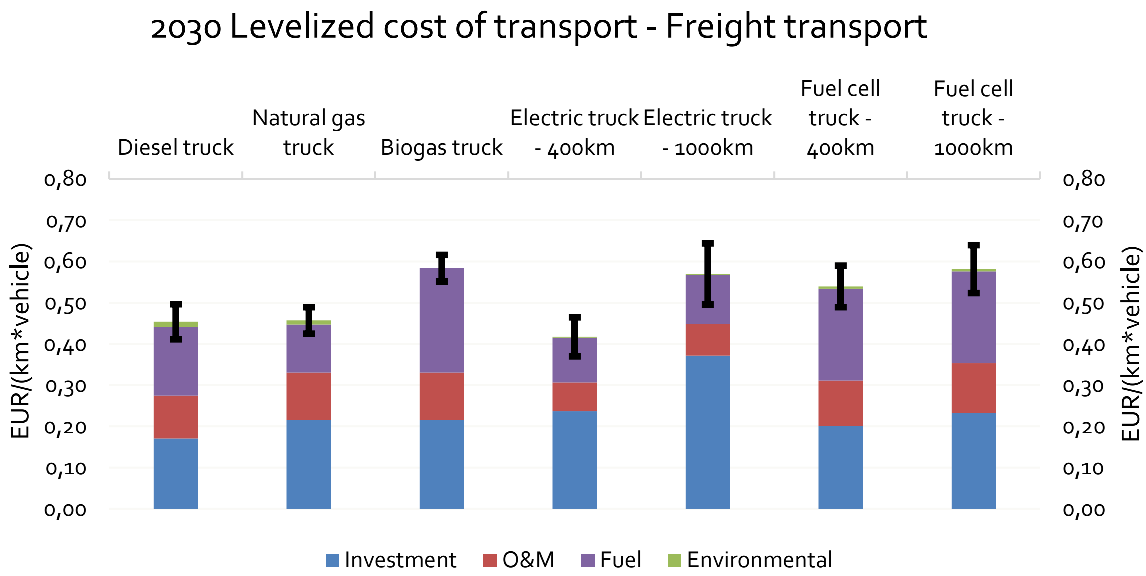

Figure 12. LCOT for freight transport (2030). Uncertainty ranges apply only to the investment costs.

Between 2030-50, significant progress is expected for electric and fuel cell trucks. The LCOT of short-range electric trucks is expected to be down to 0.36 EUR/km-vehicle; the cost rises to 0.42 EUR/km-vehicle if the driving range is extended (Figure 13). Overall, short-range electric trucks prove to be the cheapest alternative. The LCOT of fuel cell trucks drops by over 0.10 EUR/km-vehicle for both options, making the technology competitive with electric and

ICE options. Freight transport modes for long distances display very similar LCOTs in 2050. As Figure 13 shows, the main shortcoming of hydrogen-fueled lorries remains the fuel cost. Should hydrogen production be less expensive than projected, fuel cell trucks hold a vast potential in freight transport.

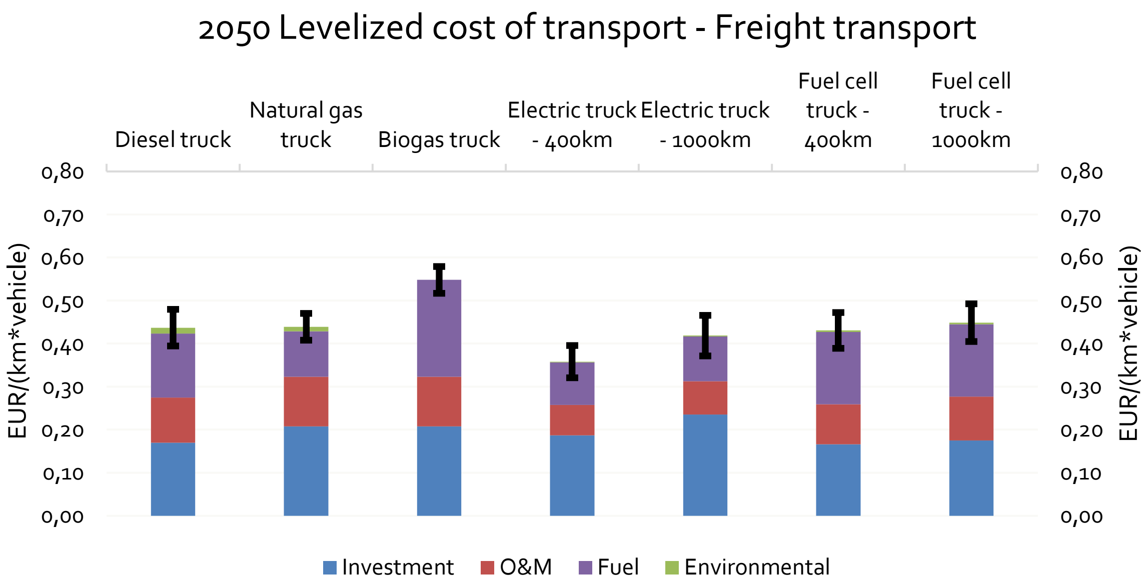

Figure 13. LCOT for freight transport (2050). Uncertainty ranges refer only to the investment costs.

Regarding the shift from natural gas to biogas in high temperature processes, both availability and price are barriers.

The process related CO2 emissions from heavy industry, mainly cement and steel and iron, requires a combination of CCS and technological shift of the core processes. Carbon neutrality cannot be obtained with existing technologies, but transformative changes are needed which requires major investments in research and development.

4 Industry

4.1 BACKGROUND AND TRENDS

In the Nordics, energy demand in the industrial sector has fallen 10% in the past years. Fossil fuel consumption has decreased 34% mainly to the advantage of biomass (Figure 14). The sector remains one of the most difficult to decarbonize due to the limited availability of clean options for process heat at medium and high temperatures. Still, the industrial sector has a key role to play in the transformation towards a climate-neutral economy and many new opportunities are in fact emerging, such as high temperature heat pumps, microwaves, infrared heating and hydrogen-based solutions. Industry is still heavily reliant on the combustion of fossil fuels in furnaces for high temperature processes, for producing steam and hot water and for space heating.

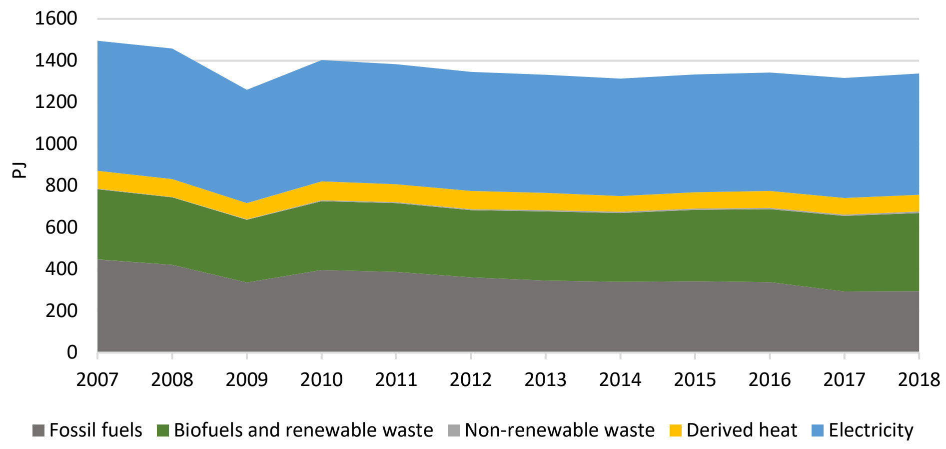

Figure 14. Energy consumption in the industrial sector by fuel type (2007-2018).

CO_2 emissions have decreased by around 22% from 2008 to 2017, Figure 15. In particular, this is due to a 33% reduction in oil consumption. Also, the use of natural gas has decreased by 13%. Norway is the Nordic country with highest release of CO_2 emissions from industry, not the least due to oil and gas extraction.

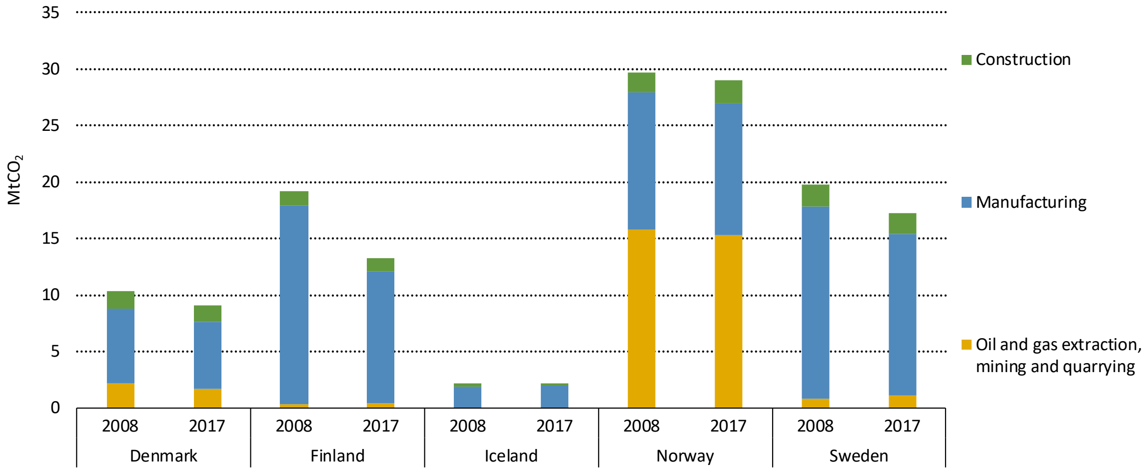

Figure 15. CO_2 emissions from the industrial sector in the Nordic countries, years 2008 and 2017.

Finland and Sweden are the Nordic countries with most energy intensive industries, such as pulp and paper and iron and steel industries. Due to this, Finland and Sweden have the highest industrial energy use, as shown in Figure 16. Norway and Iceland are characterized by electricity intensive industry, specifically primary aluminum production. Both Denmark and Norway have a large share of refineries in their industrial sectors.

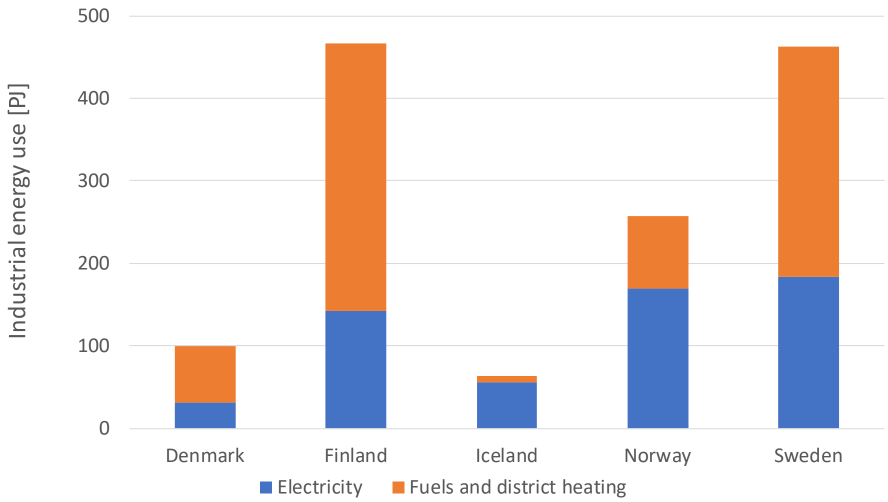

Figure 16. Industrial energy use in the Nordics year 2018. (Eurostat)

Currently, most industries are using conventional utility structures with a boiler station to supply either steam or hot water which can then be distributed throughout the production facility to provide process heat. These central utility systems are often designed to meet the highest temperature in the production processes and are thereby supplying steam or hot water at a much higher temperature than what is actually required by the production processes. For example, in the food and beverage sector, steam boilers at 8 bar (160°C) are commonly used, despite the majority of the process heating demand being required below 100 °C. However, other industries require much higher temperatures and more advanced technologies to produce certain products. This is specifically true for heavy industries such as the cement, brick and glass industries. Often these high temperatures are supplied via direct heating, where the fuel is combusted inside the production processes within the furnace.

High temperature processes are often heated with direct natural gas firing, for example in the steel industry where temperatures around 1,200°C are required. Strictly technically speaking, it is possible to replace fossil gas with biogas of high quality, but the barriers are availability and price.

However, today, several electrification technologies have become commercially available. These technologies have the potential to completely change the way industries are currently producing process heat. Additionally, the electricity mix in the power production sector will undoubtedly move toward a higher renewable energy penetration in future years. This further grows the potential in transitioning towards using electricity as the main energy carrier in industrial energy systems as the gained CO_2 reductions become more significant. Electrification of the industry sector could also offer a co-benefit by providing additional flexibility to the electricity grid operators in terms of flexible demands.

Regarding CO_2 emission in heavy industries, a vast part is not related to energy use but to the processes themselves. Particularly in cement industry and iron and steel industry, the CO_2 emissions origin from processes. In the cement industry, about 60-70% of the CO_2 emissions origin from the calcination process. Even if the fuel is switched to 100% renewables, there will still be need for CCS in order to make the cement industry carbon neutral. Research is ongoing for an electricity heated clinkering process which would remove the fossil fuels[11]. Another advantage with the new process, is that the off gases will become a pure CO_2 stream. Hence, the CO_2 capture will be less energy demanding and less expensive (Cementa and Vattenfall, 2018).

In the iron and steel industry, about 45-50% of the CO_2 emissions origin from iron ore reduction in blast furnaces. Currently there are three blast furnaces in Sweden and two in Finland. However, there are alternative reduction processes which could remove the vast part of the emissions. The HYBRIT[12] process which is developed in Sweden aims to produce fossil-free steel using hydrogen produced from fossil-free electricity as reducing agent instead of coke. The process has potential to cut Swedish CO_2 by 10% and Finland's by 7%.

The chemical industry release CO_2 since they use their by-products as fuel. Since the feedstock is fossil, the by-products have fossil origin as well. Technically, alternative feedstock is possible to use, but price and availability are barriers. Bio-based naphta could be used in the existing steam crackers for olefin production, or alternatively, there are several options on bio-based plastic production pathways, e.g. methanol-to-olefins and ethanol-to-olefins.

One additional part of Nordic heavy industry is the pulp and paper sector. In both Finland and Sweden, pulp and paper production is part of basic industry. However, despite of large energy use, the fossil greenhouse gas emissions are low. This is because most of the energy that is used origins from the byproducts from the pulp production in chemical pulp mills, mainly bark and black liquor[13]. A small fossil oil use remains, below 5% of the total fuel use, e.g. in the lime kilns which are part of the chemical recovery. The oil use is decreasing. Regarding electricity, the chemical pulp mills have steam turbines to produce a large part of the electricity demand. Some pulp and paper industries sell bark and bio-oils and even have a surplus of electricity that is delivered to the grid. In addition, excess heat is delivered to near-by district heating systems. In order to further valorize the by-products from the pulping process, numerous development projects are ongoing; not the least to produce bio-based vehicle fuels.

[11] Cem Zero project, Cementa and Vattenfall.
[12] Hydrogen Breakthrough Ironmaking Technology (HYBRIT), https://www.hybritdevelopment.com
[13] Black liquor is the waste liquor after the pulping process in which the fibres in the wood have been extracted. It has a high energy content since it contains the remaining parts of the wood: lignin and hemi-cellulose.

4.2 METHODOLOGY

To be able to sufficiently model the industrial sector, the energy services in the sector have been clearly defined based on temperature levels and whether the technologies are used for direct or indirect heating. The defined temperature levels of the energy services can be summarized as:

- Space heating (SH)
- Medium Temperature (MT) process heat below 150°C
- High Temperature (HT) process heat above 150°C

For MT and HT process heating both direct and indirect heating methods have been defined. The direct heating processes are especially used within the heavy industries for providing the very high temperature demands. The technologies that have been included in the modelling of the industry sector are listed in Table 14. Furthermore, the technologies have also been divided into temperature levels and direct or indirect heating methods.

Table 14. Process heating technologies divided into temperature levels and direct and indirect heating types.

	SPACE HEATING (SH)	MEDIUM-TEMPERATURE (MT) HEAT	HIGH-TEMPERATURE (HT) HEAT
INDIRECT FIRING	Oil boiler (Steam/hot water) Natural gas boiler (Steam/hot water) Biomass boiler (Steam/hot water) Electric boiler (Steam/hot water) Coal boiler (Steam/hot water) Traditional heat pump <80°C Heat driven heat pump <80°C High temperature abs. heat pump <150°C Booster heat pump <150°C	Oil boiler (Steam/hot water) Natural gas boiler (Steam/hot water) Biomass boiler (Steam/hot water) Electric boiler (Steam/hot water) Coal boiler (Steam/hot water) Traditional heat pump <80°C Heat driven heat pump <80°C High temperature abs. heat pump <150°C Booster heat pump <150°C Mechanical Vapor Recompression Dielectric heating Infrared heating	Oil boiler (Steam) Natural gas boiler (Steam) Biomass boiler (Steam) Electric boiler (Steam) Coal boiler (Steam) Hotdisc
DIRECT FIRING		Direct electric heating Direct natural gas firing	Direct electric heating Direct natural gas firing

Boiler technologies for producing steam or hot water have been defined for five different fuels: oil, natural gas, biomass (wood chips), electricity and coal. These technologies also have the opportunity, to be implemented as condensing boilers, in order to achieve higher efficiencies. Furthermore, four heat pump technologies have been defined for SH and MT heating demands. These heat pump technologies follow two different principles: traditional compression heat pumps (can be boosted by combining them with turbo compressors) and heat driven heat pumps (absorption type heat pumps that are driven by applying a gas or high temperature waste heat).

For MT process heat generation three additional technologies are defined:

- *Mechanical Vapor Recompression:* Vapor utilized within a process can be recompressed. Often applied in specific process types such as evaporation or drying processes
- *Dielectric heating:* Microwave and high frequency assisted heating, where a product is heated up via microwaves. Provides faster heating due to providing the heat directly inside the product.
- *Infrared heating:* Heating via infrared radiation. Applied in drying processes and can often enable faster drying compared to conventional methods.

Each technology is described in the model in terms of its heating efficiency, investment cost, fixed- and variable O&M costs and technical lifetime. All this data has been gathered from the technology data catalogue on Industrial Process Heat prepared by the Danish Energy Agency (Danish Energy Agency and Energinet, 2020). Additionally, the technology data catalogue also provides data on how large a share of the energy services each technology is potentially able to supply within certain sectors of industry (e.g. Food and beverage, commodity production, Cement and non-metallic, chemical and metals, machinery and electronics). While this data is given specifically in relation to the Danish industry sector, all the data has been adopted to the rest of the Nordic countries as well.

An overview of the utilized data for 2030 is given in Table 15.

Table 15. Main techno-economic features of heat production technologies (2030 expectations). LT: low temperature, MT: medium temperature, HT: High temperature

Technology	Investment costs [MEUR/MW]	Fixed O&M [kEUR/MW]	Var. O&M [EUR/MWh]	Total efficiency
Trad. Heat pump 80C - MT	0,65	2,00	3,20	458
Trad. Heat pump 80C - LT	0,65	2,00	3,20	458
Heat driven Heat pump 80C – MT	0,51	2,00	1,00	169
Heat driven Heat pump 80C – LT	0,51	2,00	1,00	169
High Temp abs. Heat pump 150C - MT	0,86	0,87	3,20	288
High Temp abs. Heat pump 150C - LT	0,86	0,87	3,20	288
MVR – MT	0,33	2,00	2,45	1270
Electric boiler (Steam) – HT	0,07	1,02	0,88	99
Electric boiler (Hot Water) – LT	0,06	1,02	0,88	99
Biomass boiler (Steam)	0,59	35,90	2,83	89
Direct electric heating	0,06	0,00	0,19	100
Oil boiler (Steam)	0,05	1,70	0,90	95
Natural gas boiler (Steam)	0,05	2,0000	1,10	92
Natural gas boiler (Direct firing)	0,02	0,1773	0,28	100
Coal boiler (Steam)	0,47	32,60	1,93	89

An additional consideration within the model has been the utilization of available waste heat within the industry sector itself. This is a very important consideration since the heat pumping technologies require using this waste heat as a heat source instead of e.g. the ambient air. This way the heat pumping technologies are able to reach significantly higher efficiencies. The potentials of the various heat pump technologies in the data catalogue are based on a study on the available waste heat in the Danish industry sector (Huang, Buhler, & Holm, 2015). In this study the available waste heat and its temperature levels were analyzed for different sectors, including the industry sector. The available waste heat in the industrial sector typically comes from boiler losses, cooling/refrigeration processes and high temperature processes such as evaporation, drying and distillation processes. As the mix of technologies changes from being based on central boilers, to perhaps rely more on heat pump technologies, the amount of available waste heat should also change which is why the waste heat has been defined endogenously in the model, based on the technologies and the temperature demands (setting a base waste heat generation from HT, MT and SH demands). The waste heat that is not utilized within the industry itself furthermore has the opportunity to be used as district heating in the residential heating sector.

Regarding the process related CO_2 emissions in heavy industry, the alternatives presented in Table 16 have been included in the model. In addition, CCS is included as alternative for all industries.

Table 16. Alternative technologies in heavy industry which are included in the model

Industrial sector	Alternative technology	Earliest year of introduction	Investment cost [EUR/Mt]
Iron and steel (blast furnaces)	Direct reduction with hydrogen (DRI – EAF)	2030	(DRI) 261 EUR/Mt DRI + (EAF) 222 EUR/Mt crude steel
Cement	Electric heating of clinker kiln (plasma technology)	2030	180 EUR/Mt clinker
Chemical (olefin production)	Bio oil in steam cracker	2020	421 EUR/Mtpa olefins
	Methanol-to-olefins	2020	412 EUR/Mtpa olefins
	Ethanol-to-ethylene	2020	342 EUR/Mtpa olefins

4.3 RESULTS

The comparison among technologies is drawn on the Levelized Cost of Heat (LCOH), which is defined as follows:

$$LCOH = I + \left(\frac{\sum \frac{O + Fuel + Env}{(1+r)^y}}{\sum \frac{Q}{(1+r)^y}} \right)$$

where Q is the heat produced in year y.

The LCOH of the technologies have been calculated and are compared within each of the defined temperature levels in the model. For HT energy services, the LCOH of the available technologies is shown in Figure 17. It is seen that these energy services are still expected to rely on steam boilers and direct fired furnaces.

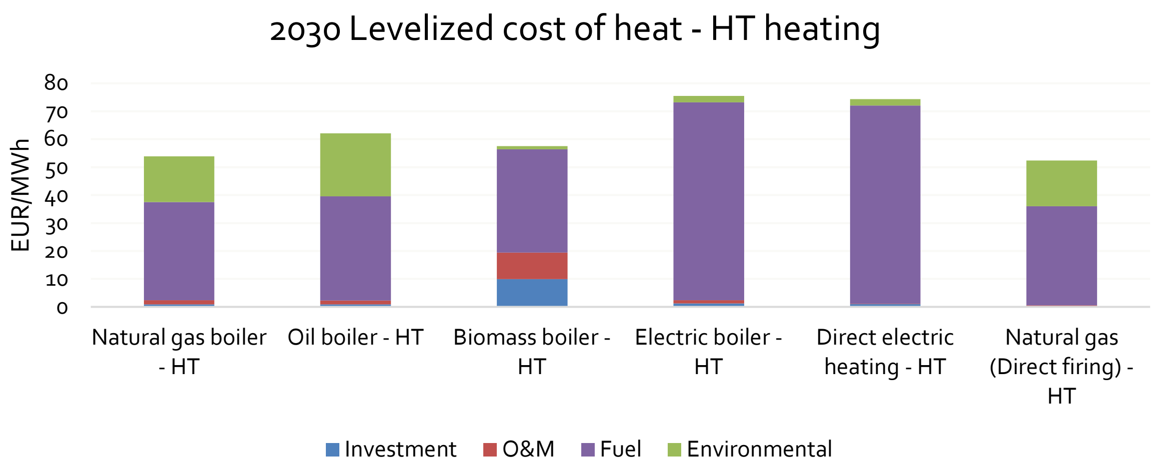

Figure 17. LCOH for HT heating technologies (2030).

Figure 17 shows that despite having a lower environmental cost, the two technologies that are using electricity come out as being the most expensive. This is due to the much higher fuel costs related to using electricity compared to natural gas, oil and biomass.

For the MT energy services more technologies become available such as heat pumps and MVR's. A comparison of the main technologies is shown in Figure 18. It is seen that some of the technologies listed in Table 15 have not been carried over to the LCOH analysis which is due to their low application potential. This is for example the case for dielectric and infrared heating. It is seen that the most expensive technologies are still electric boilers and direct electric heating. However, the cheapest technologies are the new heat pumps and MVR technologies that can be used for MT process heating. These technologies have much higher investment costs than the conventional boilers, but due to their high efficiencies they are capable of producing process heat at a lower LCOH. However, as described in the technology catalogue (Danish Energy Agency and Energinet, 2020), these technologies are not able to cover the entire process heating demand and will therefore need to be backed up by conventional or electric boilers. The traditional heat pump at 80°C is able to cover between 14-22% of MT energy services depending on the industry sector. The MVR is especially useful for evaporation, distillation, and drying processes, meaning that it can cover between 31-41% of MT energy services in food and beverage, cement and concrete and chemical industries, while it can only cover about 5% of the process heat demand for commodity production and the metal industry. Decarbonizing MT heating could therefore be realized through a combination of electrifying with heat pumps and MVR's and installing biomass steam boilers to cover the remaining demand.

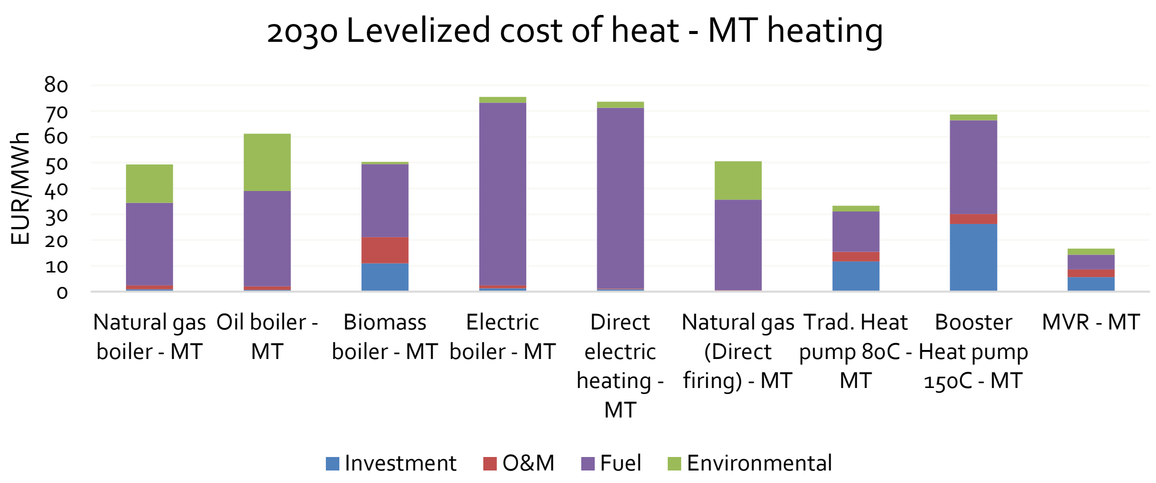

Figure 18. LCOH for MT heating technologies (2030).

The final energy services are for space heating purposes. The LCOH of the various technologies are shown in Figure 19. Many of the same technologies can also be used for SH and LT purposes. However, the MVR technology which was the cheapest MT technology cannot be used since LT processes do not include e.g. evaporation. However, unlike the MT energy services, the LT energy services can potentially be entirely covered by traditional heat pumps, and it is therefore expected that many industries will be installing heat pumps for LT processes and SH purposes in the near future.

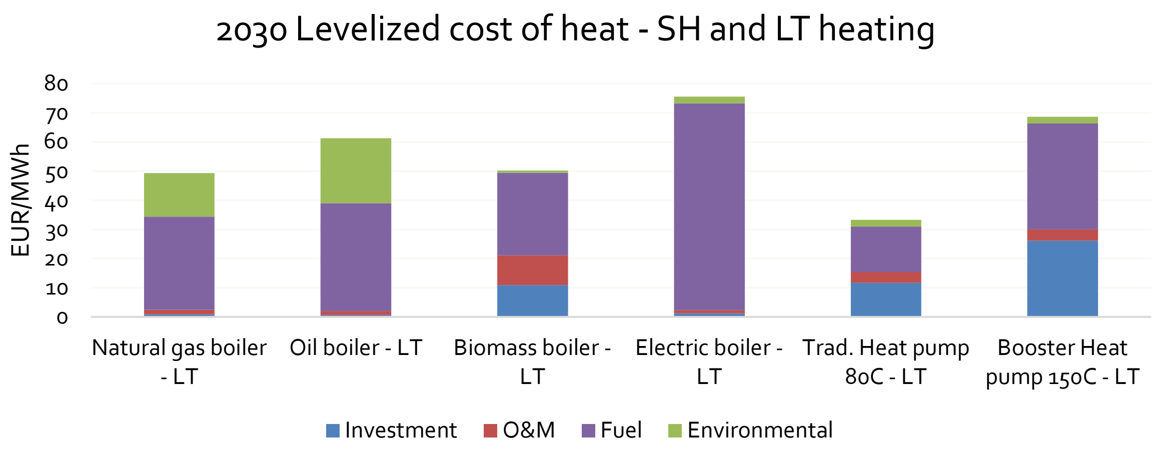

Figure 19. LCOH for SH and LT heating technologies (2030).

Generally, the results of the LCOH analysis show that the electrification of industry still is facing some challenges. The recent developments in traditional heat pumps have made these able to cover the entire LT energy service. However, moving to MT services, the heat pumps can only cover less than half of the energy demand and will therefore require some sort of conventional back-up. Here, economic challenges arise for central electric steam boilers and a decarbonization is therefore more feasible through combining electrification and biomass. Finally, the biggest challenge is decarbonizing HT processes, due to technological limits of the heat pumping technologies and the high cost of electricity compared to e.g. natural gas.

4.4 DISCUSSION

For electrification specifically, one of the main hurdles remaining is the ratio between especially the natural gas price and the electricity price. This is evident when comparing electric boilers to the conventional boilers, where despite having a higher efficiency, the LCOH is still much higher on the electric boilers due to the high electricity prices. This also underlines why more efficient technologies (i.e. heat pump technologies) are required in order to overcome the initial price hurdle. However, for heat pumping technologies, the main limitation has been to provide sufficiently high temperatures that can be used in a variety of industries.

Regarding the shift from natural gas to biogas in high temperature processes, both availability and price are barriers.

The process related CO_2 emissions from heavy industry, mainly cement and steel and iron, requires a combination of CCS and technological shift of the core processes. Carbon neutrality cannot be obtained with existing technologies, but transformative changes are needed which requires major investments in research and development.

5 Green Fuels

5.1 BACKGROUND AND TRENDS

Green fuels encompass a broad category of synthetic and alternative fuels whose production process and/or final use release low-to-zero greenhouse gases into the atmosphere. Zero-carbon energy carriers (e.g. based on electricity and heat from renewable sources) will make alternative fuels 100% green in future years.

Green fuels are pivotal to pursuing far-reaching decarbonization targets. Sectors which are more challenging to decarbonize and where electrification can occur limitedly to selected end-uses (such as transport and industry) demand alternative fuels to substitute fossil options. The broad spectrum of technologies and processes considered in this chapter comprises both well-established and promising solutions.

While this study covers only direct input-output processes, the production chain can reach notable levels of complexity, as shown in Figure 20 for jet fuel/fuel oil. The green fuels sector is still in its early stages and optimal production pathways will depend on the geographical location, demand across end-use sectors, infrastructure and technological development. The competition with other decarbonization options such as electrification will also determine to which extent a complex transformation chain will develop.

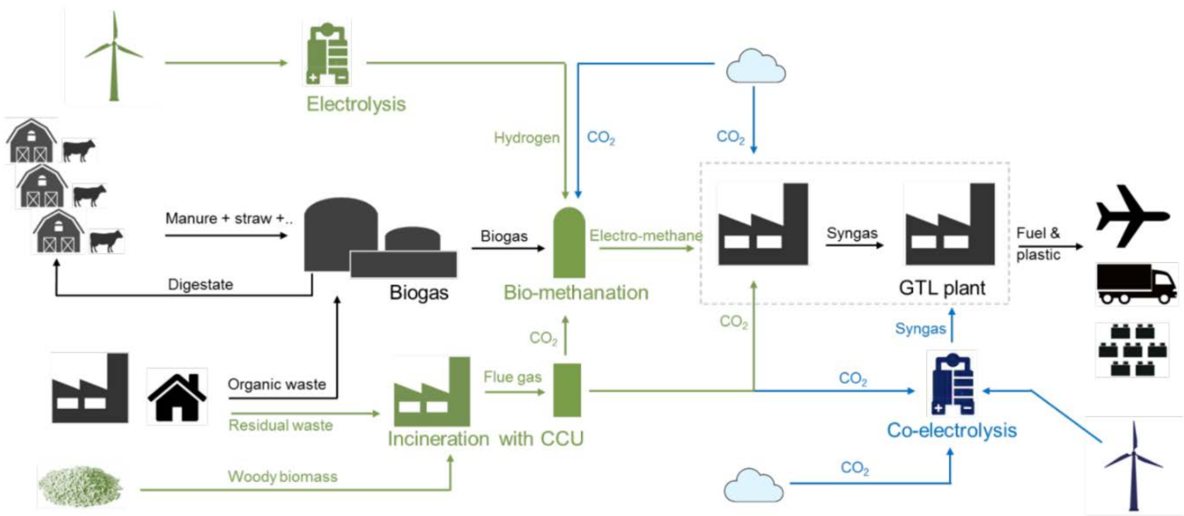

Figure 20. Linking of processes for the production of jet fuel. Source: (Mortensen, et al., 2019).

For the purpose of this study, green fuels are divided into liquid and gaseous fuels. Since a wide set of output commodities is involved, a snapshot of the sector's development portrays technologies with different levels of maturity and application. By way of example, biofuels have carved out an important role in the transportation sector (Figure 20) while hydrogen has so far struggled, mainly because of technological barriers and high production costs. Sector-specific decarbonization targets also impact on the prospects of a production pathway: sectors inching forward into decarbonization delay innovation efforts.

Biofuels for transportation are at the core of the comparison among liquid fuels. Some of these products might also find a limited application in heating and cooling, albeit other alternatives (for instance heat pumps) are expected to dominate the market in future years. Certain liquid biofuels can be blended with refined oil products in ICEs, currently in limited shares (e.g. methanol with gasoline); other e-fuels, typically resulting from the Fischer-Tropsch synthesis, can fully substitute fossil counterparts.

While still confined to selected industrial processes (e.g. ammonia synthesis), hydrogen use is foreseen to grow rapidly. The interest in hydrogen economies is motivated by the extensive applications hydrogen might have, such as in:

- Medium-to-high-temperature industrial processes
- The refining industry, for further conversions into other fuels (e-fuels)
- The transport sector
- The power and gas sectors, as an alternative to or blended with natural gas.

Biogas is the other central gaseous fuel in this study. Biogas accounted for 10% of the gas carried through Danish gas pipelines at the end of 2019, with peaks of 25% during summertime, yet the potential is vast and largely unexploited (IEA Bioenergy Task 37, 2019). In Sweden, 55% of the biogas produced is upgraded to biomethane and used in the transportation sector, due to favourable support schemes (2018, (Swedish Gas Association, 2019)). Sweden is not covered by a widespread gas network, which is limited to the South-West of the country. Biogas facilities can be one of the centres mentioned at the beginning of this Section, where a complex hub for green fuels production shapes up. The raw syngas contains roughly 30-40% CO_2 in volume before it is upgraded into biogas for the gas grid. CO_2, which needs to be removed beforehand, would in this case be a commodity available on site for the synthesis of e-fuels. Similar considerations are valid for other centres where co-locating facilities makes economic sense, such as industries if CCS gains momentum. Indeed, the creation of a CO_2 economy (production centres, pipelines, hubs etc.) would have a positive influence on the green fuels case.

Ultimately, the following challenges pose a hurdle for the green fuels economy to develop:

- The complexity of the value chain, which requires infrastructure to be in place for an ample set of commodities
- The competition among different uses of green electricity
- The availability of cheap fossil counterparts
- The relatively high costs of technology options for e-fuels production

Several factors can contribute to a swift take-off of the green fuels economy, mostly linked to sector coupling opportunities. The geographical location is of the essence. Production facilities sited close to demand centres, an existing and fitting gas grid, the presence of harbours and a potential, local market for by-products (e.g. heat) are a few examples. Altogether, these synergies can be decisive to speed up the uptake of green fuels value chains. Power prices are also an important decision factor, as electricity is largely used for e-fuels production. Electricity supply will need to increase significantly to meet non-final energy demand and will therefore play a decisive role in the transformation sector. (Nordic Energy Research, 2020).

Selected production pathways may be favoured with respect to others depending on sector-specific climate targets. For instance, the heating and cooling and the transport sectors are likely to follow two decarbonization trajectories at different paces. Even if both would benefit from the green fuels economy picking up, alternatives (e.g. direct electrification, heat pumps) might penalize certain production pathways and favour others.

Finally, this analysis also covers ammonia production from electrolysis. Ammonia (NH_3) usage scaled up in the past century, thanks to the availability of natural gas at relatively low costs. It is widely used as a fertilizer and is synthesized in Haber-Bosch processes from hydrogen and nitrogen. While ultimately "green ammonia" does not solve downstream issues linked to soil pollution and damaged ecosystems, its synthesis could ideally be fossil-free. Ammonia could also hold some potential in the heating and cooling sector as a refrigerant/heat pump fluid and could help decarbonize the shipping industry.

5.2 PROCESS DESCRIPTION AND ASSUMPTIONS ON TECHNOLOGY DATA

Green fuels are categorized into *liquid* and *gaseous* fuels. In broad terms, this distinction is tied to different target sectors fuels have within each category. Liquid fuels mostly address decarbonization needs in the transport sector, while gaseous fuels can play a key role in both the transport and the heating and cooling sector. Even so, it is possible to use green liquid fuels for heating purposes (for example low-quality, heavy biooil).

A categorization of the liquid fuels and processes is provided in Table 17. The processes considered here are not meant to represent all the possible pathways for the production of liquid fuels; they are rather a selection relevant for the Nordic countries and reflecting the process maturity.

Table 177. Processes for the production of green liquid fuels.

Production of green liquid fuels		
Process	**Input commodities**	**Output fuels and by-products**
Methanol from power	Electricity, CO2	Methanol, heat
Methanol from biomass	Wood chips, electricity	Methanol, heat
Biomass gasification and FT synthesis	Wood chips	Naphta, jet fuel, diesel, heat
Hydrothermal liquefaction	Wood chips, electricity	Fuel oil
Fast pyrolysis bio-oil	Wood chips, electricity	Fuel oil, heat, electricity
Catalytic hydroprocessing	Wood chips, electricity	Fuel oil, char, gas, heat
Catalytic hydropyrolysis	Wood chips, hydrogen	Gasoline, diesel, char, gas
Hydrogen to liquid fuel (FT synthesis)	Hydrogen, CO2	Jet fuel, various hydrocarbons, heat

Due to the variety of processes under study, output fuels are not directly comparable with each other in their chemical composition and therefore in their calorific value and applications. As an example, fuel oil produced from pyrolysis has a high oxygen and water content, which makes it suitable for limited end-uses, such as in oil burners (unless it is further refined). In addition, outputs of the same processes can be systematically different because of variable inputs (e.g. biomass feedstocks) and complex reactivity (e.g. in Fischer-Tropsch reactors).

The processes in Table 17 ground in one or more of the following pathways:

- *Gasification*, where a feedstock is converted into syngas in a high-temperature, controlled environment and in presence of either oxygen or steam
- *Pyrolysis*, where a feedstock is converted into syngas in an (nearly) oxygen-free environment
- *Thermochemical conversion in a liquid environment*, where a feedstock is converted into a liquid fuel in a high temperature, pressurized aqueous environment

- *Water electrolysis*, where electricity splits water molecules into hydrogen and oxygen
- *Fischer-Tropsch synthesis*, where hydrogen, carbon monoxide and other reactants produce different liquid hydrocarbons.

The gases resulting from some of these processes are subsequently converted into liquid fuels in other reactors. For a more detailed description of the processes refer for instance to (Danish Energy Agency and Energinet, 2020).

Table 18 carries the gaseous end-use fuels considered in this analysis.

Table 188. Processes for the production of green gaseous fuels.

Production of green gaseous fuels		
Technology/process	**Input commodities**	**Output fuels and by-products**
Alkaline electrolyser	Electricity	Hydrogen, heat
PEM electrolyser	Electricity	Hydrogen, heat
Solid oxide electrolyser (SOEC)	Electricity, heat	Hydrogen, heat
Steam methane reforming	Natural gas, electricity	Hydrogen
Biogas digestor	Manure, electricity, heat	Biogas
Haber-Bosch (ammonia, from electrolysis)	Electricity	Ammonia, heat

Hydrogen production from water electrolysis is the result of the following elementary reaction

$$H_2O \rightarrow H_2 + O_2$$

Hydrogen obtained via water electrolysis (*green hydrogen*) represents an alternative to traditional steam reforming processes, which have been the industry standard for over a century. Hydrogen used for industrial purposes is as of today still produced from natural gas and – to a lesser extent – coal. When combusted in air, hydrogen does not release CO_2 and thus is a carbon-free alternative when electrification is either unattractive or impossible.

Hydrogen produced from fossil fuels can have a lower environmental impact if CO_2 is sequestered after a reforming process (*blue hydrogen*). Two main reforming processes exist: steam reforming and auto-thermal reforming. The main difference lies in the way energy is supplied to the (endothermic) process, that is through an external source (steam reforming) or by direct oxidation of the gas within the reactor (auto-thermal reforming). The first concept is significantly more widespread and is therefore treated in this report. In broad terms, the process converts methane and water into hydrogen and carbon dioxide. CO_2 separations of 95% and more can be achieved in the sequestration process (The Oxford Institute for Energy Studies, 2020). Indeed, the market attractiveness of blue hydrogen depends also on the natural gas price.

There are several reasons why fossil gas is hard to replace in energy systems. While alternatives have proven to exist - and are deployed - in the power sector, substitutes are at an early stage of development in end-use sectors such as industry and households. A solution allowing to use existing assets comes from biogas, which is currently mainly produces in digestors, landfills and wastewater treatment plants. This gas has a lower calorific value than hydrogen or natural gas, but it can be upgraded and blended with fossil gas in the grid (or directly used for power and heat generation). In digestors – which are treated in this report - bacteria decompose biomass, agricultural residues and manure in temperature-controlled environments into a gas mainly composed of hydrogen, carbon monoxide and carbon dioxide. Catalysers support the reactions. Manure or the biomass feedstock can be of different thermodynamic and chemical quality, therefore conditioning the composition and value of the output biogas.

The green fuels covered in this Chapter attempt to replace the usage of their fossil counterparts in all end-use sectors, particularly where electrification is not an option. Ammonia is part of the study as it holds a potential to supply part of the energy demand in selected applications. Even if ~80% of the world's NH_3 production is destined for agriculture, ammonia can also be used

- As a refrigerant or medium in reverse thermodynamic cycles, for heating and cooling purposes
- As a potential fuel in ICEs and fuel cells, since NH_3 is also a hydrogen carrier. This could contribute to the decarbonization of the marine industry for instance (Hansson, Brynolf, Fridell, & Lehtveer, 2020).

Still, significant hurdles need to be overcome for ammonia to be a viable alternative to fossil fuels; short- and medium-term prospects favour other green options over it (e.g. hydrogen). Ammonia is a toxic compound and its usability in ICEs has yet to be proven, even if demonstration projects are in the pipeline. Today, ammonia is produced in Haber-Bosch processes starting from hydrogen and nitrogen; the first is generally of fossil origin (see steam methane reforming), while the second is typically obtained from air in air separation units. The Haber-Bosch process is a well-proven technology, but the attractiveness of green ammonia from electrolysis mainly depends on the electricity price, as air separation and water electrolysis are power-intensive.

Table 19 shows the main techno-economic parameters for selected green fuels technologies included in the models. The source for the data is mainly the Danish Technology Catalogue for Renewable Fuels (Danish Energy Agency and Energinet, 2020); selected cost figures have been corrected with in-house data. Additional values for the year 2020 are given in the Appendix.

Table 199. Main techno-economic parameters for green fuels technologies.

Technology/process	Year	Efficiency [GJ_{out}/GJ_{in}]	Investment cost [MEUR/MW]	Fixed O&M [1000EUR/MW]	Variable O&M [EUR/GJ_{out}]
LIQUID FUELS					
Methanol from power	2030	0.57	3.16	55.24	1.83
	2050	0.60	1.58	55.24	1.83
Methanol from biomass	2030	0.50	3.15	41.96	3.50
	2050	0.56	1.57	41.96	3.50
Biomass gasification and FT synthesis	2030	0.38	4.53	60.43	0.31
	2050	0.38	4.03	40.29	0.31
Hydrothermal liquefaction	2030	0.86	1.73	65.86	4.08
	2050	0.86	1.15	65.86	4.08
Fast pyrolysis bio-oil	2030	0.62	1.20	71.94	0.79
	2050	0.65	0.73	72.63	0.79
Catalytic hydropyrolysis	2030	0.39	1.65	28.77	0.38
	2050	0.41	0.97	28.77	0.38
Catalytic hydroprocessing	2030	0.49	0.91	46.16	0.02
	2050	0.49	0.54	46.16	0.02
Hydrogen to liquid fuel (FT synthesis)	2030	0.70	1.68	-	4.92
	2050	0.75	0.94	-	2.77
GASEOUS FUELS					
Alkaline electrolyser	2030	0.66	0.63	28.85	-
	2050	0.69	0.24	26.23	-
PEM electrolyser	2030	0.62	1.02	50.76	-
	2050	0.67	0.63	31.32	-
Solid oxide electrolyser (SOEC)	2030	0.79	0.80	18.88	-
	2050	0.79	0.53	12.59	-
Steam methane reforming	2030	0.76	0.24	11.91	0.08
	2050	0.76	0.24	11.91	0.08
Biogas from digestion	2030	0.80	1.62	207.41	-
	2050	0.80	1.45	205.33	-
Haber-Bosch (ammonia, from electrolysis)	2030	0.59	2.82	84.55	-
	2050	0.59	1.90	53.43	-

Uncertainty ranges are considered for the investment cost figures in Table 20. The source is the Danish Energy Agency's technology catalogue for generation and district heat. When not available, a ± 25% interval is assumed, unless other internal estimates are available (Table 19).

Table 20. Investment cost uncertainty ranges for green fuels technologies.

Technology	Year	Uncertainty (down)	Uncertainty (up)
Methanol from power	2030	1.47	3.26
	2050	1.26	1.89
Methanol from biomass	2030	1.15	3.25
	2050	1.26	1.89
Biomass gasification and FT synthesis	2030	3.36	5.37
	2050	3.02	4.04
Hydrothermal liquefaction	2030	1.25	2.21
	2050	0.86	1.44
Fast pyrolysis bio-oil	2030	0.80	1.60
	2050	0.54	0.91
Catalytic hydropyrolysis	2030	1.09	2.22
	2050	0.73	1.22
Catalytic hydroprocessing	2030	0.59	1.22
	2050	0.40	0.67
Alkaline electrolyser	2030	0.47	0.79
	2050	0.18	0.30
PEM electrolyser	2030	0.55	1.71
	2050	0.31	1.25
Solid oxide electrolyser (SOEC)	2030	0.60	1.00
	2050	0.33	0.66
Steam methane reforming	2030	0.18	0.29
	2050	0.18	0.29
Biogas from digestion	2030	1.41	2.27
	2050	1.27	2.02
Haber-Bosch (ammonia, from electrolysis)	2030	2.08	3.40
	2050	1.42	1.91

5.3 LCOF METHODOLOGY

The comparison among technologies is drawn on the Levelized Cost of Fuel (LCOF), which is defined as follows:

$$LCOF = \frac{I + \sum \frac{O + C - H}{(1+r)^y}}{\sum \frac{F}{(1+r)^y}}$$

where C is the cost of commodities such as fuel and CO_2 when requested by the process and F the fuel output. F is an aggregator of all output products when more than one fuel type is produced (e.g. in processes yielding hydrocarbons of different nature as from the Fischer-Tropsch synthesis). FT liquids comprise a wide range of hydrocarbons, including diesel, jet fuel and naphtha. The cost of producing only a specific fuel is therefore higher than displayed in this analysis; nonetheless, it depends on the plant operating conditions and in particular on the H:C ration in input to the process. Other parameters in the LCOF formulation are identical to the LCOE formula in Section 3.3.

Operation and maintenance (O&M) costs are assumed to be equal throughout the unit's lifetime. Heat revenues are subtracted from the cash flows when heat is a by-product of the process.

LCOF calculations ground in the following assumptions:

- Cash flows are calculated for an economic lifetime of 20 years
- The socio-economic discount rate is set to 5%
- Disposal costs are disregarded.

The LCOF calculations provide a synthetic result and the values should be read in light of the type of output commodities generated from the process. In reality, cash flows change from year to year based on operations and commodity prices (in terms of both costs and revenues). For instance, heat revenues are considered to be constant over the plant's lifetime.

The attractiveness of a specific technology is also determined by its operations. In general, the higher yearly full load hours, the lower the cost of producing one fuel unit (assumptions for the full load hours of all generators are summarized in Table 21). However, units running at high capacity factors are exposed to higher average commodity prices. For instance, this influences the business case of electrolyzers, which use electricity as an input. Thus, fluctuations in the LCOFs are heavily dependent on operations and the evolution of energy markets.

Table 201. Full load hours for LCOT calculations.

LIQUID FUELS				
	Methanol from power	Methanol from biomass	Biomass gasification and FT synthesis	Hydrothermal liquefaction
Full load hours	6000	7000	6000	5500
	Catalytic hydropyrolysis	Catalytic hydroprocessing	Hydrogen to liquid fuel (FT synthesis)	Fast pyrolysis bio-oil
Full load hours	5500	5500	7000	5500

GASEOUS FUELS						
	Alkaline electrolyzer	PEM electrolyzer	Solid-oxide electrolyzer (SOEC)	Hydrogen from steam methane reforming	Biogas from digestion	Ammonia from electrolysis
Full load hours	4000	4000	4000	7000	8000	7000

5.4 LCOF RESULTS

Liquid fuels

Figure 21 summarizes the LCOF for liquid fuels production (2030). The cost ranges between 20-50 EUR/GJ (excluding potential heat revenues), depending on the process.

Processes yielding either low-quality fuels (fuel oil) or light hydrocarbons in modest fractions of the total output (catalytic hydropyrolysis, where gasoline and diesel make up roughly 50% of the process energy output) have the lowest LCOF, under 27 EUR/GJ. Heat can be sold in heat markets or re-used for industrial processes; when heat is accounted for, the LCOF can decrease by up to 3 EUR/GJ.

Processes producing high-quality marketable fuels (methanol, hydrocarbons from Fischer-Tropsch) show LCOFs between 40-50 EUR/GJ. Methanol and hydrocarbons from biomass are technologies at a very early stage of development, therefore their future costs are difficult to predict. The other two processes (Methanol from power and Hydrogen to liquid fuels) require hydrogen and CO_2 in input and enjoy successful market penetration. Methanol from power has found application e.g. in Iceland, where CO_2 is captured from a geothermal power plant and combined with hydrogen to obtain methanol; Fischer-Tropsch synthesis has been a standardized technology for decades.

Figure 21 suggests that the LCOF is heavily dependent on the fuel and CO_2 input, which constitute more than 50% of the total production cost in almost all processes. Thus, different input price assumptions might lead to significant swings in the fuel cost (see Section 7.1 in the Appendix). In the coming decade, technologies with a low degree of maturity might reduce the impact of this drawback with improvement in the conversion efficiency. For other more established processes (e.g. Fischer-Tropsch) this might not be possible, especially if the facility needs to operate at high full load hours to optimize production costs (no input price optimization).

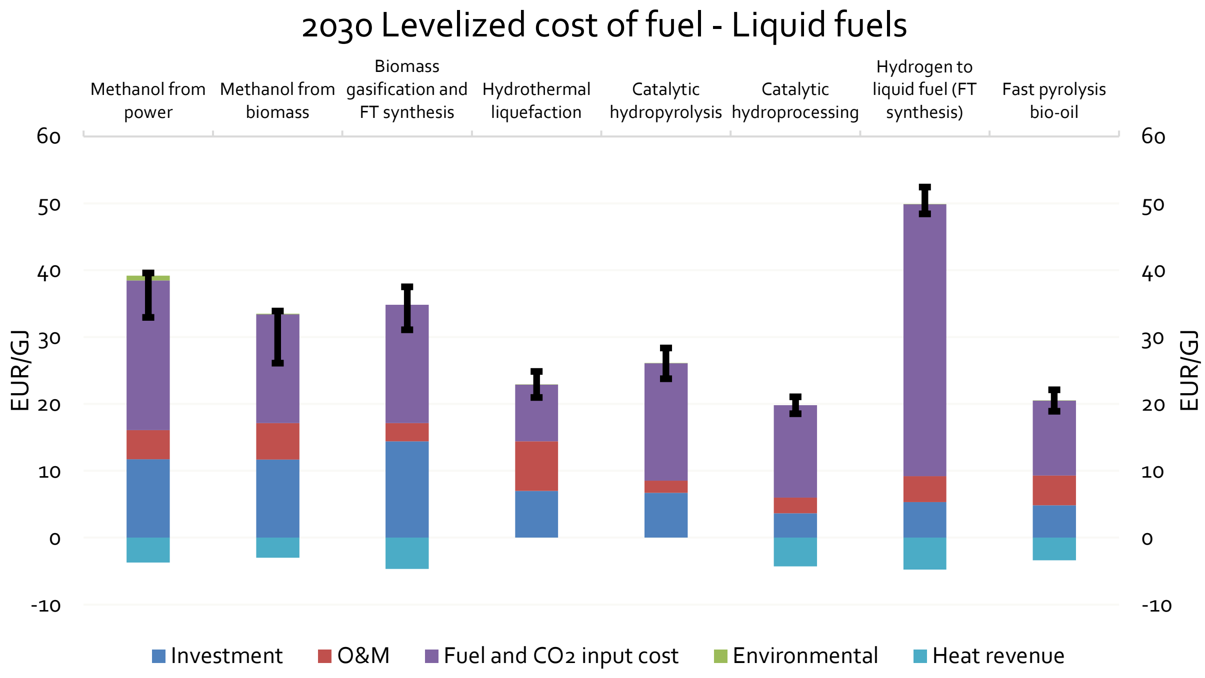

Figure 21. LCOF for liquid fuels (2030). Uncertainty ranges are applied only to the investment.

The processes yielding green liquid fuels are expected to benefit from technological advancements, which bring the overall production cost down in

2050 compared to 2030 levels (Figure 22). The cost of synthesizing hydrocarbons in FT reactors will range between 30-40 EUR/GJ, depending on the input commodity (biomass or hydrogen), with fuel and CO_2 prices being the major determinants. Methanol production costs drop to around 30 EUR/GJ. This effect is mainly ascribable to a lower initial outlay, whereas the fuel and CO_2 component remains mostly unvaried. In this study, CO_2 prices are assumed to be twice as high in 2050 than in 2030, be CO_2 an input or an output to the process. In reality, the development of a CO_2 infrastructure, the reduction of capture costs and the possible location of green fuels processes in the proximity of CO_2 sources would make CO_2 more affordable. Similarly, if electricity is generated entirely by renewables, power prices would be also lower.

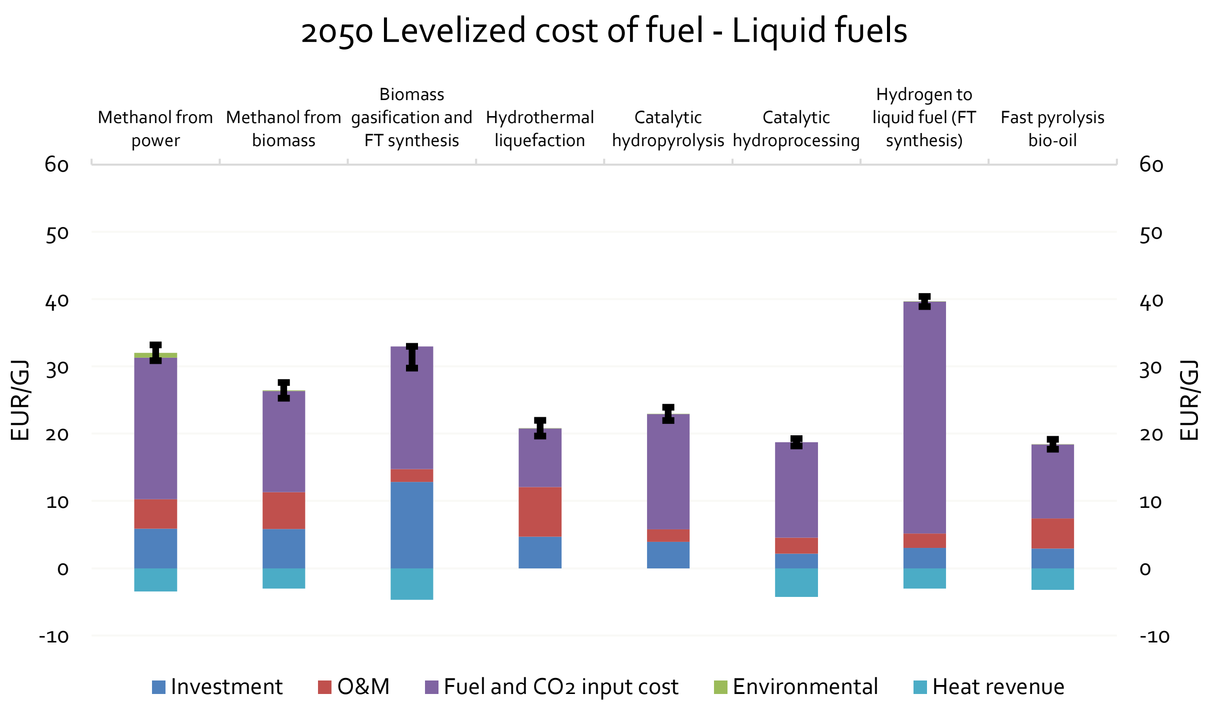

Figure 22. LCOF for liquid fuels (2050). Uncertainty ranges are applied only to the investment.

Gaseous fuels

Figure 23 summarizes the LCOF for gaseous fuels production (2030). The cost ranges between 15-27 EUR/GJ.

Green hydrogen production costs are expected to be around 20 EUR/GJ (= 2.4 EUR/kg) in 2030. As in the case of liquid fuels (but here more accentuated), the final cost per unit output is markedly dependent on the electricity cost. Electrolyzers might find it advantageous to optimize their operations in order to cut electricity costs and at the expenses of investment cost amortization. Blue hydrogen costs are projected to be around 15 EUR/GJ; without CCS, hydrogen from steam methane reforming settles below the 10 EUR/GJ mark. This is a consequence of low fossil prices, as shown in Section 7.1).

Biogas from digestion costs lie around the 17 EUR/GJ mark, the final figure depending on the feedstock (manure in this study). However, different feedstocks deliver raw biogas of different quality, which then influence the upgrading costs. These can be assumed to be around 2 EUR/GJ. Biogas from digestion is an established technology and minor technological changes are expected in the future, mainly linked to biogas refining. Environmental costs are shown with a negative contribution, as the GHG emissions associated with non-treated manure (N_2O, CH_4, …) or other feedstocks are avoided.

Ammonia plants running at high capacity factors (7000 full load hours a year) can supply the fuel at a cost lower than 30 EUR/GJ in 2030. Such an achievement, potentially outclassed by further reduction in the electricity price, might pave the way to a broad cross-sector utilization of green ammonia, from transport to heating and cooling.

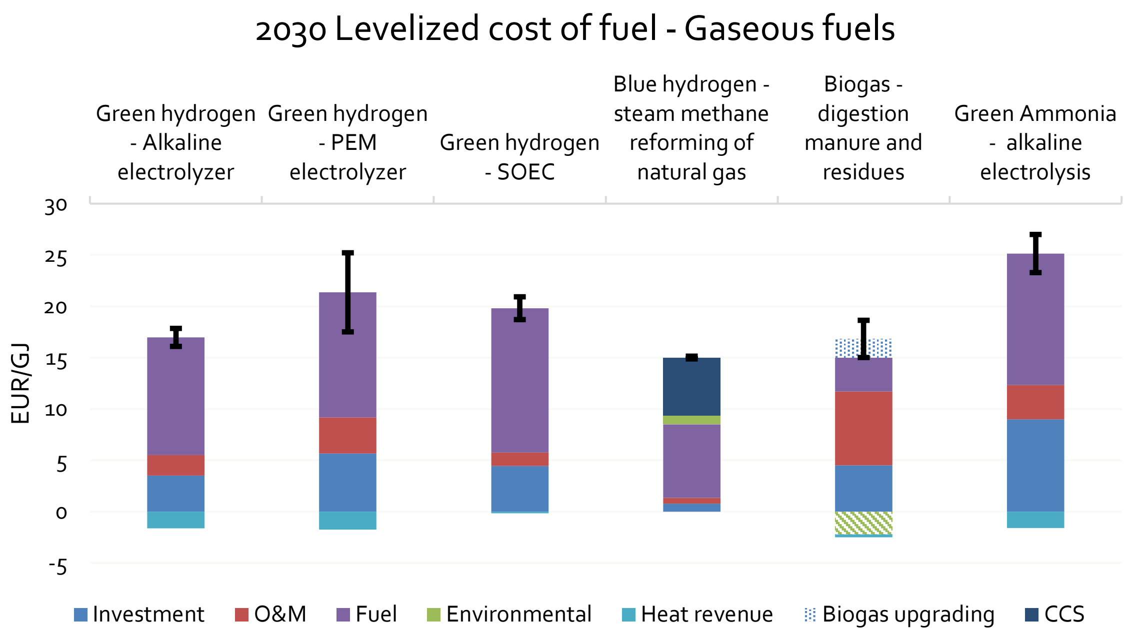

Figure 23. LCOF for gaseous fuels (2030). Uncertainty ranges are applied only to the investment.

In 2050, hydrogen produced from electrolysis will be even cheaper. Depending on the electricity price, tariffs and location, green hydrogen production costs could range anywhere between 3-17 EUR/GJ (= 0.4-2.0 EUR/kg). All the other green fuels considered display an LCOF below 20 EUR/GJ, the only exception being ammonia, which is set to cost slightly more than 23 EUR/GJ (Figure 24).

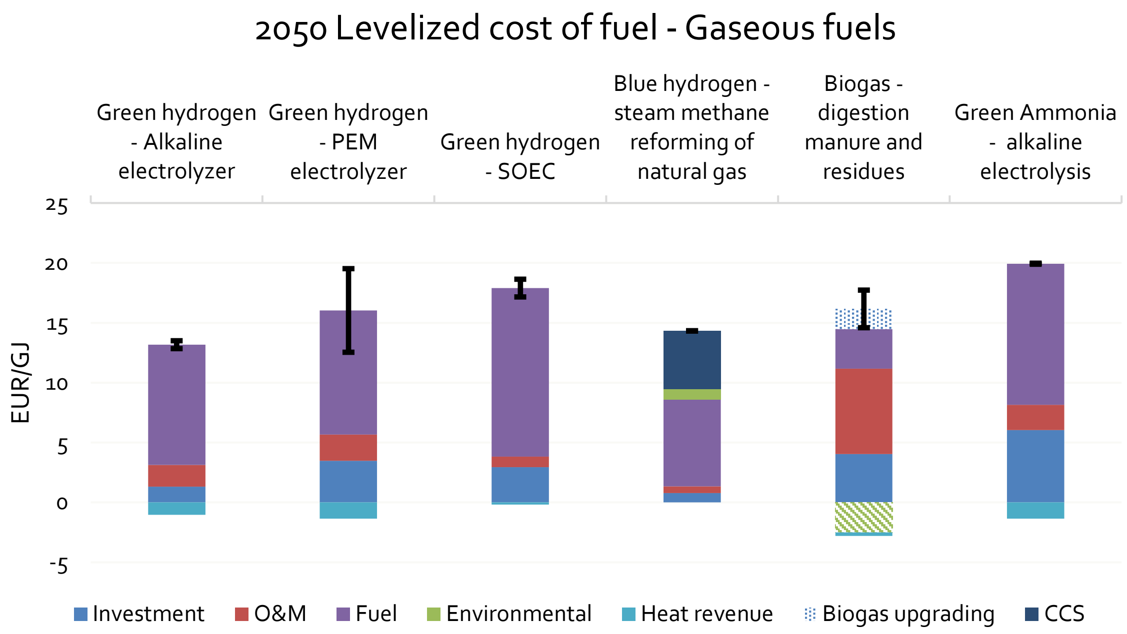

Figure 24. LCOF for gaseous fuels (2050). Uncertainty ranges are applied only to the investment.

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Appendix A

A.1 FUEL AND COMMODITY PRICES

Fuel, feedstock, and commodity prices are a key assumption for cost of energy calculations. As for spot market prices, in this publication:

- Fuel and CO_2 prices are based on the Sustainable Development Scenario developed by the IEA in the World Energy Outlook 2020.
- Electricity and heat prices in input are NCES estimates and serve illustrative purposes. A three-step cost curve is envisioned for the electricity spot price (30, 35, 40 EUR/MWh) and a two-step cost curve for heat prices (6, 9 EUR/MWh). Step curves are introduced to distinguish between high and low capacity factor technologies and processes. The step size is in line with what is recommended by the the Danish Energy Agency's *Analyseforudsætninger*[14].
- Some prices are internally linked in the calculations. This occurs when the commodity is one of the analysed process outputs and is then further converted into another carrier/commodity. An example is biogas as a green fuel which then is used for power generation.

When fuels and commodities make use of additional infrastructure to fuel the energy conversion processes in this study, a mark-up is included on top of the market price. This is the case of selected

- Transport technologies. A 3 EUR/GJ surcharge is added on top of diesel and gasoline market prices, 4 EUR/GJ for natural gas. As for electric vehicles, the electricity price for industrial uses in *Analyseforudsætninger*[14] is used ("an værk").
- Industry technologies. Fuel and electricity spot prices are increased according to *Analyseforudsætninger*.

Prices are summarized in Table A.1. Pollutants are priced according to the Danish Energy Agency's assumptions (*Analyseforudsætninger*)[14], which is also used for emission factors of fuels and commodities.

Table 21. Fuel and commodity prices used in this study. Unit: EUR/GJ, otherwise expressed.

Fuel/commodity		2020	2030	2050
FUELS and FEEDSTOCKS				
Coal		1.9	2.1	2.0
Natural gas	Market price	4.8	4.8	4.9
	Consumer price (industry)	5.2	5.2	5.3
	Consumer price (transport)	8.8	8.8	8.9
Biomass (wood chips)		6.4	6.7	7.0
Manure		1.7	1.7	1.7
Biogas (upgraded)		19.0	19.2	18.9
Fuel oil		8.4	7.5	6.7
Diesel	Consumer price	15.6	14.7	13.9
Gasoline		15.9	15.0	14.2
Hydrogen	Consumer price	36.7	24.8	21.7
Uranium	Fuel and waste treatment	0.66	0.66	0.66
COMMODITIES				
Electricity	Spot price	8.3 (50% CF) 9.7 (65% CF) 11.1 (80% CF)	8.3 (50% CF) 9.7 (65% CF) 11.1 (80% CF)	8.3 (50% CF) 9.7 (65% CF) 11.1 (80% CF)
	Consumer price (transport and industry)	19.1	19.5	19.5
Heat	By-product / process input	9.0 (low CF) 6.0 (high CF)	9.0 (low CF) 6.0 (high CF)	9.0 (low CF) 6.0 (high CF)
CO_2 - carbon price [EUR/t]		27.4	79.2	125
CO_2 – process input [EUR/t][15]		27.4	79.2	69.8
SOx [EUR/kg]		2.5	2.5	2.5
NOx [EUR/kg]		1.9	1.9	1.9
Particulate matter [EUR/kg]		6.0	6.0	6.0

[14] Data can be accessed at the following link: Analyseforudsætninger.

[15] CO_2 used as an input commodity for the production of green fuels is priced at the minimum between the quota price and the average estimated capture and storage costs in that year.

A.2 WIND RESOURCE AND TECHNOLOGY

In the LCOE calculations, the onshore turbine is assumed to be installed in medium-wind sites, i.e. locations with an annual average wind speed between 7-8 m/s at 100m above ground. This is representative of some wind regions in the Nordics, despite differences exist. Denmark and Iceland are endowed with a greater wind resource on average (high-wind sites), whereas Finland is rather a low-wind region. High-wind sites are present also in Norway and Sweden, but the resource is less uniform than in Denmark and Iceland (Figure A.1).

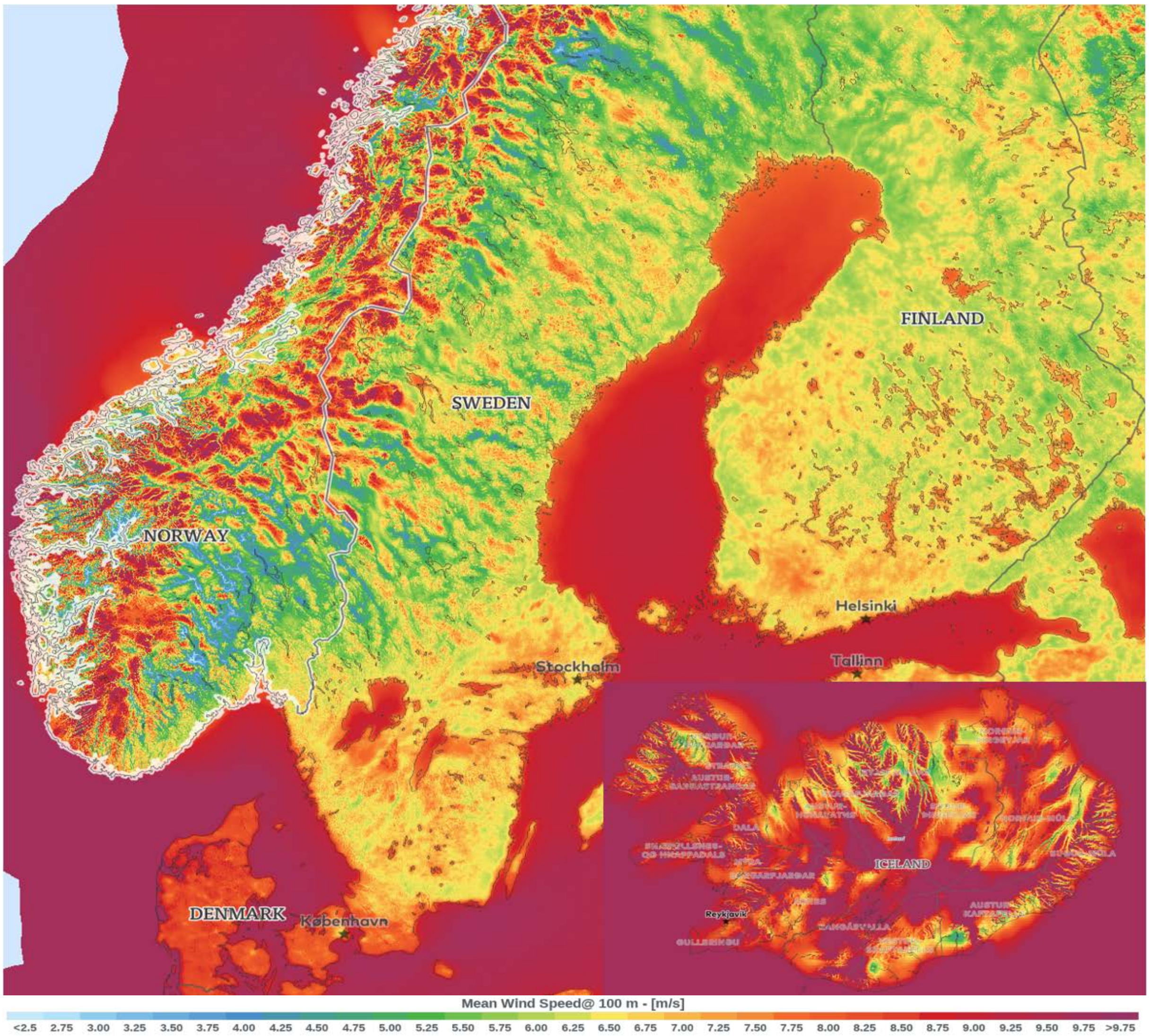

Figure A.1. Wind resource map for the Nordic countries. Source: Global Wind Atlas.

In low-wind sites, turbines are taller and larger to achieve yields comparable to those in high-wind sites. This comes at a higher initial outlay. Thus, the medium-wind turbine displays intermediate cost figures, which should be adapted to reflect the site characteristics.

A.3 SOLAR RESOURCE

The solar resource is strongly dependent on the site latitude. Figure A.2 shows the quality of the resource in the Nordic areas covered by the Global Solar Atlas, that is for latitudes approximately under 60°N. Denmark and the Southern regions of Sweden are the most favourable regions for solar PV, with annual Global Horizontal Irradiations (GHI) over 1000 kWh/m². The yearly GHI can be a first approximation of the full load hours at a specific location. Hence, the 1000 full load hours assumption used in this study considers the sites that are best suited for PV installations. In the map reported in Figure A.2, over two thirds of the land is hit by a GHI between 1000-1100 kWh/m² (broad geographical potential). In the future, the projected cost decline of photovoltaic modules might make utility-scale PV an attractive option also in sites with lower irradiation.

Figure A.2. Solar resource (Global Horizontal Irradiation) in the Nordic countries. Source: Global Solar Atlas.

A.4 ADDITIONAL TECHNOLOGY DATA

This section holds technology data for the year 2020 for all technologies under consideration.

Technology	Year	Typical plant size [MW]	CHP	Electric Efficiency [%]	Total efficiency [%]	Investment cost [MEUR/MW]	Fixed O&M [1000EUR/MW]	Variable O&M [EUR/MWh]
RENEWABLE GENERATORS								
Onshore wind	2020	100	No	-	-	1.31	19.11	1.78
Offshore wind	2020	500	No	-	-	2.18	41.06	3.04
Solar PV	2020	20	No	-	-	0.44	7.12	0.00
BASE LOAD								
Coal CHP plant	2020	500	Yes	46	89	1.90	31.00	2.90
Combined cycle CHP plant	2020	500	Yes	56	80	0.89	29.65	4.45
Biomass CHP plant (wood chips)	2020	500	Yes	41	101	2.60	70.00	2.60
Coal CHP plant with CCS	2020	500	Yes	32	67	4.60	116.37	7.44
Combined cycle CHP plant with CCS	2020	500	Yes	40	77	2.49	49.77	3.30
Biomass CHP plant with CCS (wood chips)	2020	500	Yes	29	63	6.04	198.94	5.89
Nuclear power plant (PWR)	2020	1000	No	35	35	4.50	-	10.70
Nuclear power plant (PWR) - refurbishment	2020	1000	No	35	35	0.93	85.00	-

PEAK LOAD								
Coal power plant – condensing	2020	100	No	46	46	1.73	26.73	2.50
Open-cycle gas/biogas turbine	2020	50		39	39	0.53	16.70	3.77

Technology	**Year**	**Efficiency [MJ/vehicle-km]**	**Investment cost [1000EUR/vehicle]**	**Fixed O&M [1000EUR/vehicle /year]**
PASSENGER CARS				
Gasoline car	2020	1.95	14.94	700
Diesel car	2020	1.89	16.66	800
Natural gas car	2020	2.31	17.93	800
BEV – 300 km range	2020	0.65	27.03	420
BEV – 500 km range	2020	0.69	32.71	700
Plug-in hybrid (gasoline+battery)	2020	1.34	25.02	700
Fuel cell car	2020	1.21	29.88	900
FREIGHT TRANSPORT				
Diesel truck	2020	12.02	110.00	10470
Natural gas/biogas truck	2020	14.03	143.56	11517
Full electric truck – 400 km range	2020	6.00	198.53	7000
Full electric truck – 1000 km range	2020	6.88	373.75	7700
Fuel cell truck – 400 km range	2020	9.91	160.58	14137
Fuel cell truck – 1000 km range	2020	9.95	183.08	15424

Technology/process	Year	Efficiency [GJ_{out}/GJ_{in}]	Investment cost [MEUR/MW]	Fixed O&M [1000EUR/MW]	Variable O&M [EUR/GJ_{out}]
LIQUID FUELS					
Methanol from power	2020	0.55	4.74	0.06	1.83
Methanol from biomass	2020	0.45	5.67	0.06	5.25
Biomass gasification and FT synthesis	2020	0.33	5.04	0.12	0.31
Hydrothermal liquefaction	2020	0.86	2.31	0.07	4.08
Fast pyrolysis bio-oil	2020	0.60	2.01	0.08	0.79
Catalytic hydropyrolysis	2020	0.38	2.92	0.03	0.38
Catalytic hydroprocessing	2020	0.49	1.60	0.05	0.02
Hydrogen to liquid fuel (FT synthesis)	2020	0.65	2.20	-	6.47
GASEOUS FUELS					
Alkaline electrolyser	2020	0.64	1.38	0.03	-
PEM electrolyser	2020	0.58	1.99	0.10	-
Solid oxide electrolyser (SOEC)	2020	0.76	3.04	0.07	-
Steam methane reforming	2020	0.76	0.24	0.01	0.08
Biogas from digestion	2020	0.80	1.79	0.20	-
Haber-Bosch (ammonia, from electrolysis)	2020	0.59	3.48	0.10	-

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Nordic Clean Energy Scenarios

The project Nordic Clean Energy Scenarios aims to identify and help prioritise – through scenario modelling – the necessary actions up to 2030 and map potential long-term pathways to carbon neutrality. This report guides you through the Nordic energy system and illustrates how the Nordic countries can achieve the **Nordic Vision 2030**, to become the most sustainable and integrated region in the world, and make the green transition towards carbon neutrality a reality.

The Nordic Clean Energy Scenario analyses resulted in five solution tracks that capture the most significant options for successfully meeting the Nordics carbon neutrality targets: direct electrification; power-to-X (PtX fuels); bioenergy; carbon capture technologies (CCS) including in combination with bioenergy (BECCS); and behavioural change. A decarbonisation pathway that balances elements of all five solution tracks will likely be easier to realise and be the most resilient.

The differences between the Nordic countries' energy systems are a strength to realising our climate goals, while the development of necessary infrastructure, between and within countries, emerges as a major challenge. Making concerted planning, citizen involvement, and new cost distribution mechanisms instrumental, for a cost-effective and socially acceptable transition of the Nordic energy sector and for ensuring its contribution to Europe as a whole.