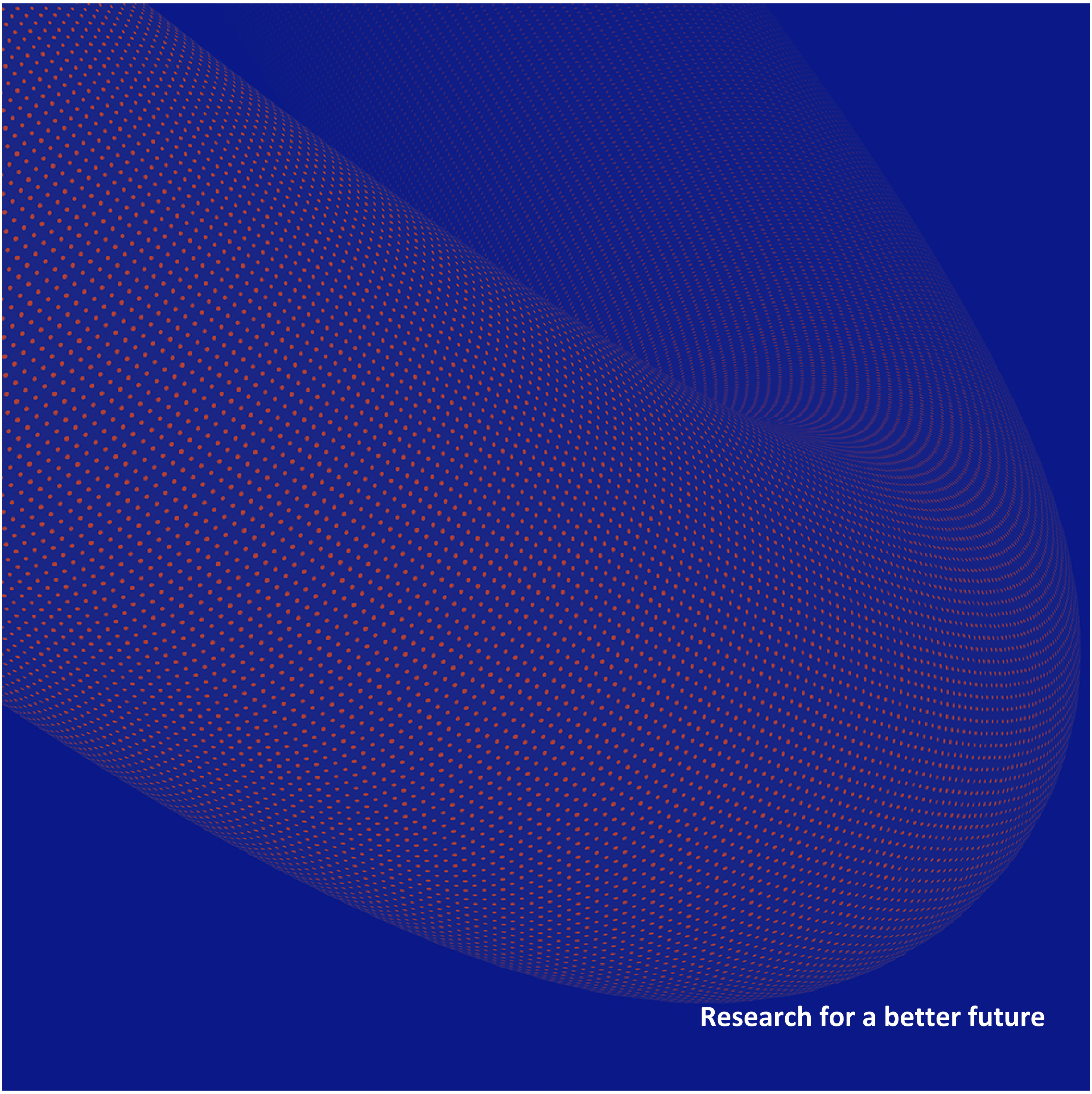
Documentation of IFE-TIMES-Norway v3

IFE/E-2022/013



Report number: **IFE/E-2022/013**	ISSN: 2535-6380	Availability: Public	Publication date: 2023-02-20
Revision:	ISBN: 978-82-7017-943-5	DOCUS-ID: 57346	Number of pages: 86
Client:			
Title: Documentation of IFE-TIMES-Norway v3			

Summary:

The development of the energy system model IFE-TIMES-Norway started in 2017 in cooperation with the Norwegian Water Resources and Energy Directorate (NVE). This report describes the model version 3 from December 2022, with several updates made throughout the model since previous model documentation (2021). The model is based on earlier versions of TIMES-Norway (2009) and MARKAL-Norway (1992). The model development is dynamic with continuously methodological developments.

IFE-TIMES-Norway is a long-term optimisation model of the Norwegian energy system that is generated by TIMES (The Integrated MARKAL-EFOM System) modelling framework. TIMES is a bottom-up framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. TIMES models provide investments and operational decisions that minimize the total discounted cost of a given energy system that meets the future demand for energy services. The total energy system cost includes investment costs in both supply and demand technologies, operation and maintenance costs, and income from electricity export to and costs of electricity import from countries outside the model.

IFE-TIMES-Norway is a technology-rich model of the Norwegian energy system that is divided into five regions that corresponds to the current spot price areas of the electricity market. The model provides operational and investment decisions from the starting year, 2018, towards 2050, with model periods for every fifth year from 2020 within this model horizon. To capture operational variations in energy generation and end-use, each model period is split into 96 sub-annual time slices, where four seasons is represented by 24 hours each. The model has a detailed description of end-use of energy, and the demand for energy services is divided into numerous end-use categories within industry, buildings and transport.

Prepared by:	Kristina Haaskjold; Eva Rosenberg; Pernille Merethe Sire Seljom
Reviewed by:	Kari Aamodt Espegren
Approved by:	Mari Lyseid Authen
Report distribution:	For external, open

Institute for Energy Technology
P.O. Box 40, NO-2027 Kjeller, Norway / P.O. Box 173, NO-1751 Halden
Telephone: +47 63 80 60 00/ +47 69 21 22 00
www.ife.no / firmapost@ife.no

Contents

1 Introduction

IFE-TIMES-Norway is a long-term optimisation model of the Norwegian energy system that is generated by TIMES (The Integrated MARKAL-EFOM System) modelling framework in the VEDA interface. The Norwegian energy system model, TIMES-Norway, was developed in cooperation between the Norwegian Water Resources and Energy Directorate (NVE) and Institute or Energy Technology (IFE), starting in 2017, with a continuous development through several projects. This model development was based on restructuring and updates of earlier versions of TIMES-Norway that was deployed in another interface, the Answer interface. The first version of TIMES-Norway was available in 2009 which was built on the MARKAL-Norway (MARKAL is the predecessor of TIMES) model, that was developed from 1990. NVE and IFE has further developed the TIMES-Norway model into two different directions due to different modelling needs, and the model version of IFE is denoted IFE-TIMES-Norway.

The TIMES modelling framework is developed within the ETSAP (the Energy Technology Systems Analysis Program) IEA implementing agreement during several decades [1] and has a modular approach using the modelling language General Algebraic Modelling System (GAMS). GAMS translate a TIMES database into the Linear Programming (LP) matrix. This LP is submitted to an optimizer and result files are generated. Two different user faces are possible, Answer and VEDA [2]. IFE-TIMES-Norway applies the VEDA user interface, that is developed and maintained by KanOrs [3].

TIMES is a bottom-up framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. TIMES models minimize the total discounted cost of a given energy system to meet the demand for energy services for the regions over the period analysed at a least cost. The total energy system cost includes investment costs in both supply and demand technologies, operation and maintenance costs, and income from electricity export to and costs of electricity import from countries outside the model [4-6].

IFE-TIMES-Norway is a technology-rich model of the Norwegian energy system divided into five regions corresponding to the current electricity market spot price areas. The model provides operational and investment decisions from the starting year, 2018, towards 2050, with model periods for every fifth year from 2020 within this model horizon. To capture operational variations in energy generation and end-use, each model period is divided into 96 sub-annual time slices, where four seasons is represented by a day of 24 hours.

The model has a detailed description of end-use of energy, and the demand for energy services is divided into numerous end-use categories within industry, buildings and transport. Note that energy services refer to the services provided by consuming a fuel and not the fuel consumption itself. For example, the heating demand in buildings is an energy service while the fuel used to heat the building is not. Each energy service demand category can be met by existing and new technologies using different energy carriers such as electricity, bio energy, district heating, hydrogen and fossil fuels. Other input data include fuel prices; electricity prices in countries with transmission capacity to Norway; renewable resources; technical potentials; and technology characteristics such as costs, efficiencies, and lifetime and learning curves.

This report describes the status of IFE-TIMES-Norway by December 2022 and is an update of the report of 2021 [7]. It is written for modellers used to the TIMES vocabular and the objective is to describe and document the content of the model in the present status. A schematic view of general TIMES inputs and outputs is presented in Figure 1. How this is applied to IFE-TIMES-Norway is presented in Figure 2.

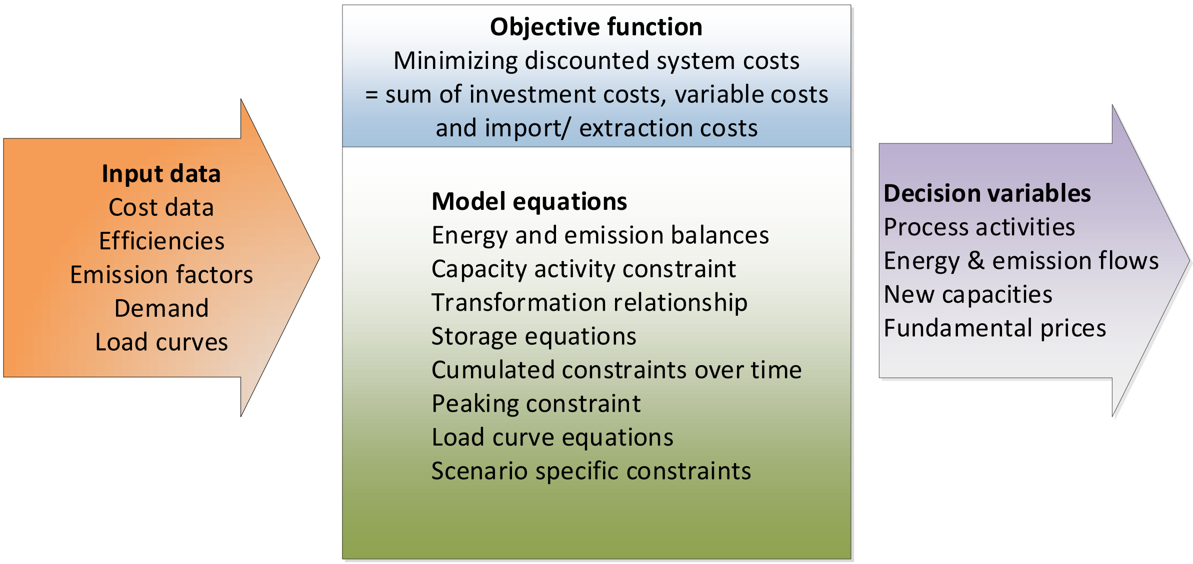


Figure 1 Schematic of TIMES inputs and outputs

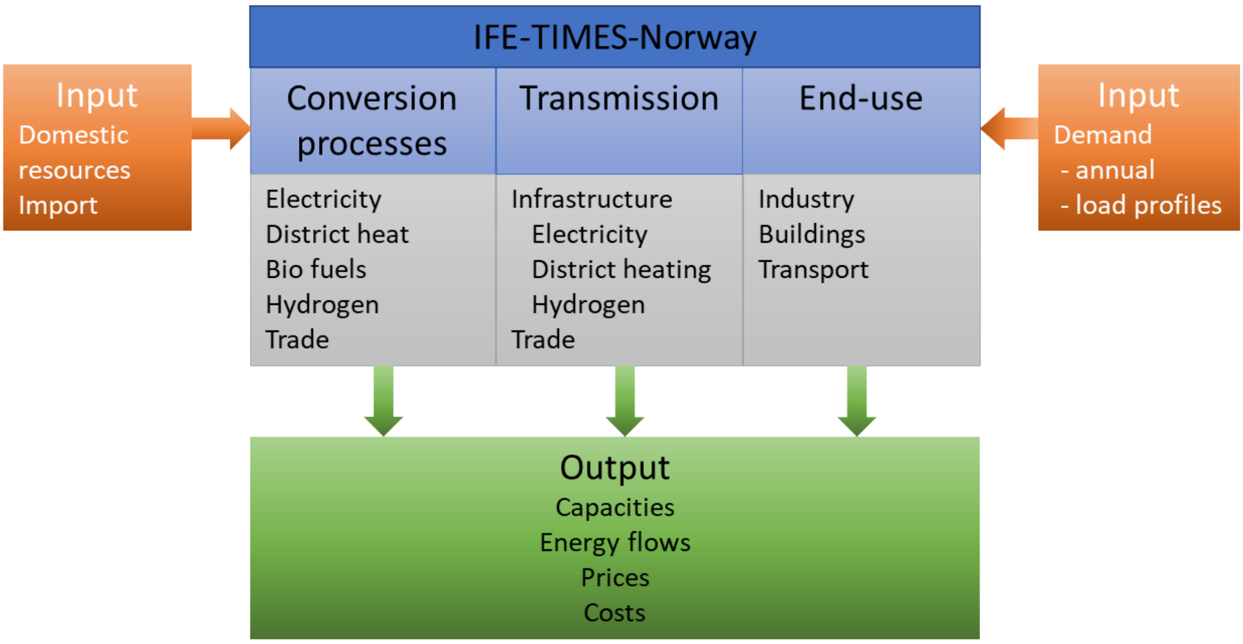


Figure 2 Schematic of IFE-TIMES-Norway

2 Model structure

The model input and design are structured in several excel files where each of these files are described in the following chapters. An overview of the main content of these files are presented in Table 1.

The overall model characteristics such as base year, time periods, regions, time-slices, discount rate (incl. year for discounting), units etc, is defined in the SysSettings file. The present data used are:

- Regions: NO1, NO2, NO3, NO4, NO5 (the five Norwegian electricity spot price regions), see Figure 3 and the offshore regions Utsira, Sørlige Nordjø II, Sandskallen, Frøyagrunn, Frøyabank and Stadthavet
- Start year 2018
- Times slices (see Figure 4)
    - 4 Seasons (Fall, Spring, Summer, Winter)
    - 24 hours per day (DayNite: 01, 02, 03,…., 24)
- Discount rate: 4%
- Discount year: 2018
- Currency: kNOK2016
- Activity unit: GWh
- Capacity unit: MW
- Commodity unit: GWh

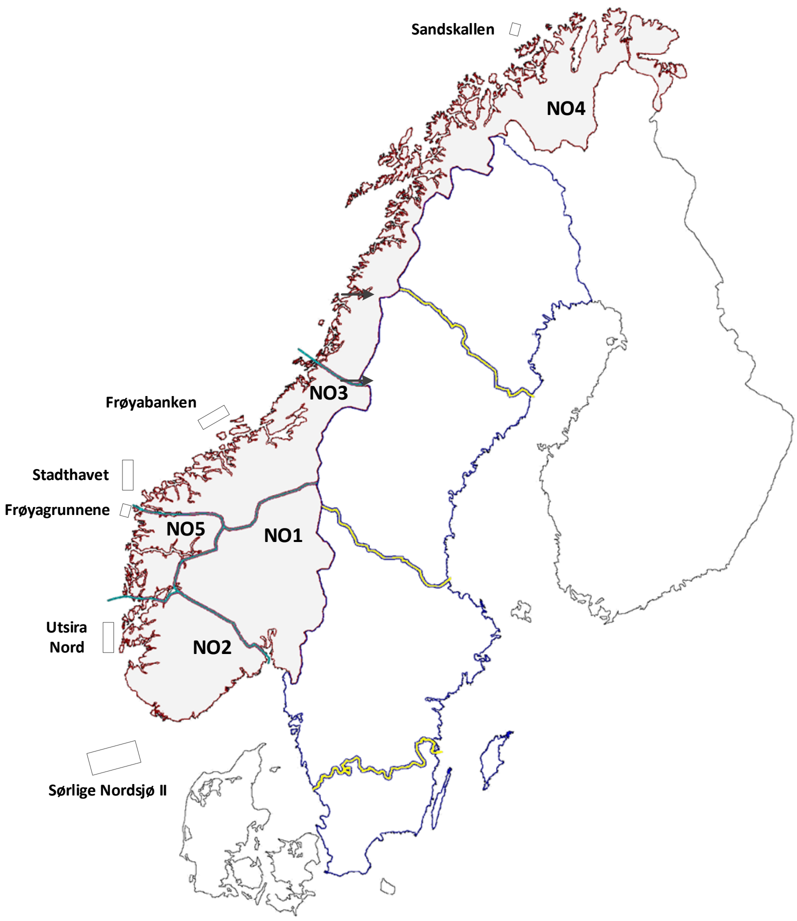


Figure 3 Regions included in IFE-TIMES-Norway, NO1 to NO5 and offshore regions

The currency of the model is kNOK2016 since that was the available data when the model was first developed. When adding new technologies, often more recent currencies are used, without recalculating to NOK2016. The reason for this is both that the difference in consumer price index is low (1.8% from 2016 to 2018) and that many data are rough estimates with much higher uncertainty than the change in KPI.

The modelling horizon is easily changed in the analyses. A usual set of modelling periods is presented in Figure 4, consisting of 5 year-periods after the initial two periods of 2018 and 2020. The times slice level can also be changed, but it requires more work, since different load profiles must be changed as well. The length of the four seasons is the same: 25% of a year. Spring is defined as March – May, Summer is June – August, Fall is September – November and Winter are December – February. The total number of annual time slices is 4 * 24 = 96.

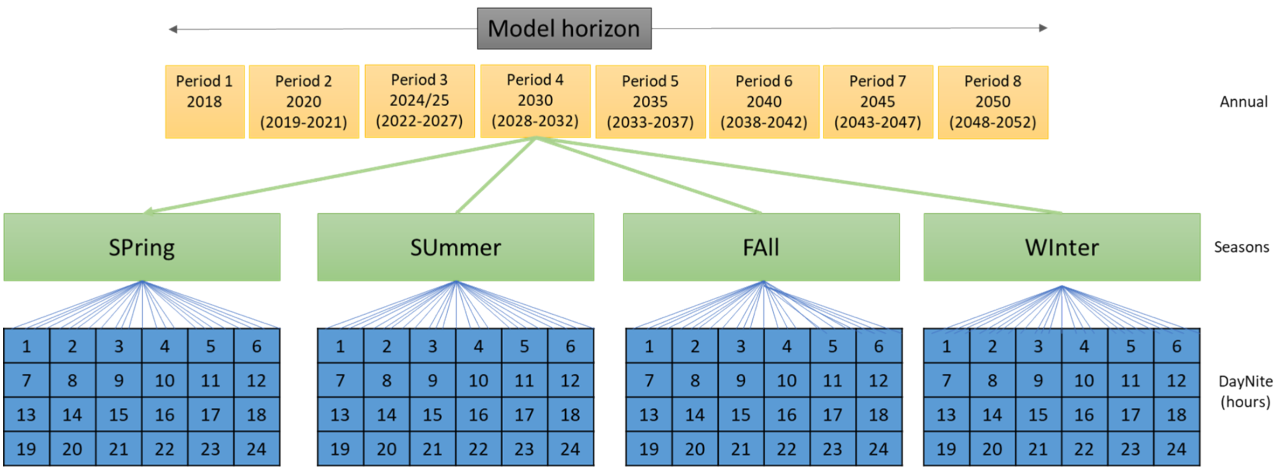


Figure 4 Time slice tree of IFE-TIMES-Norway (base version)

An overview of the different files included in IFE-TIMES-Norway is presented in Table 1. The model consists of seven basic files representing the end-use sectors buildings, industry and transportation and the energy sectors power, offshore power and district heating. In addition, all fuels are defined in "Fuels". The power file includes hydro, wind and PV, while CHP is included in the DistHeating-file. No gas power or other thermal power plants are included.

Different scenario files are developed, and they are typically project specific and not further described here. SubRES files can only include new technologies, not included in base year templates. In IFE-TIMES-Norway, CCS is included as SubRES files. Electricity trade parameters are defined in the Trade-files.

Profiles are collected in the scenario file "Base profiles". This file includes profiles of demand, hydro power inflow, wind power, EV charging, heat pump efficiencies and solar capacity factors.

Assumptions often used in analyses are gathered in the scenario file "Base assumptions". This file includes energy taxes, CO2-price, subsidies for EV, minimum requirement of zero emission trucks (EU), growth constraint for new vehicles, electricity trade prices and biomass balance. This is described in more detail in the sector chapters.

Table 1 Overview of model files and main content in IFE-TIMES-Norway

Model files	Content
SysSettings	Starting year, time periods, time slices, regions, discount rate, units, exchange rates etc.
VT_Norway_Power	Electricity generation technologies (except offshore wind and CHP) Production potentials / limitations / costs
VT_Norway_Offshore_power	Offshore wind technologies Production potentials / limitations / costs
VT_Norway_DistHeating	District heating technologies Production potentials / limitations / costs
VT_Norway_Fuels	Fuel definitions, prices, potentials (biomass, waste, waste heat) Technology specific delivery costs Hydrogen & bioenergy production technologies CO2 emissions
VT_Norway_Industry	Annual demand Demand technologies incl. potentials / limitations
VT_Norway_Buildings	Annual demand Demand technologies incl. potentials / limitations
VT_Norway_Transport	Annual demand Demand technologies incl. potentials / limitations
Trades	Power trade links & parameters (existing and new)
Scen_Base_Profiles	Time-slice profiles of demand and resources
Scen_Base_Assumptions	Norwegian biomass balance, electricity trade prices, electricity fees
SubRES_xxx	New technologies in different SubRES files, e.g. CCS
Scen_xxx	Different scenario files with e.g. alternative demand, technology sensitivities, CO2 prices etc.

In the following, the model is described based on the functionality and the chapter headings are not always equal to the content of the files of the model. One example is the profiles that are described together with the technology and not in a separate chapter of Base_Profiles.

The investment costs in IFE-TIMES-Norway are aiming to include the entire cost of installation, including costs for land and the necessary land and infrastructure preparation costs. However, all the costs are not always possible to identify. For investments which needs considerable construction time, also costs of capital in form of interest cost during construction time are included.

The TIMES modelling framework can either be deterministic or stochastic, where the stochastic modelling approach can both consider short-term and long-term uncertainty [8]. IFE-TIMES-Norway is currently in several projects using stochastic programming to consider the short-term uncertainty of e.g., weather-dependent renewable electricity supply and heat demand. As illustrated in e.g. [9-12], a two-stage stochastic model can be used to provide investment decisions that explicitly value flexibility by considering a set of operational situations that can occur, due to the short-term uncertainty of weather-dependent supply and demand. The stochastic modelling approach is however not the focus of this version of model documentation.

3 Energy carriers

The main rule is that electricity commodities are defined in the power file, commodities in district heating in the DistHeating file and most other commodities in the fuels file. Internal commodities such as heating commodities and local PV production are included in the end-use files (Buildings or Industry).

The commodities produced in IFE-TIMES-Norway are electricity, district heat, hydrogen and some bio energy products. The power file includes electricity generation and is described in the power chapter of this report. Production of district heat is included in the file DistHeating and is described in the district heating chapter of this report.

Bio energy is used across all sectors and the production of some bio energy products is included in the fuels file.

Hydrogen is used in the transport and industry sectors and is included in the fuels file.

The electricity commodities are:

- ELC-HV (high voltage)
- ELC-LV (low voltage)
- ELC-REG (electricity from regulated hydropower)
- ELC-RUN (electricity from run-of-river)
- ELC-WIND (electricity from wind power)
- ELC-LV-COM (electricity to commercial buildings)
- ELC-LV-IND (electricity to mineral industry, district heating plants, agriculture, construction, local electrolyzers, air, other mobile transport)
- ELC-LV-IND-L (electricity to light industry)
- ELC-LV-RESM (electricity to multi-family houses)
- ELC-LV-RESS (electricity to single-family houses)
- ELC-PV-RESM (electricity from residential solar power in multifamily houses)
- ELC-PV-RESS (electricity from residential solar power in single family houses)
- ELC-PV-COM (electricity from commercial solar power)
- ELC-PV-IND (electricity from solar power in industry)
- ELC-PV-PARK (electricity from solar power park)
- ELC-CAR (electricity for battery powered cars, after charger, defined in transport file)
- ELC-VAN (electricity for battery powered vans, after charger, defined in transport file)
- ELC-HD-COM (electricity for battery powered trucks, after slow charger, defined in transport file)
- ELC-HD-FAST (electricity for battery powered trucks, after fast charger, defined in transport file)

Electricity produced locally in single-family houses can only be used in single-family houses or sold to the low voltage grid. Similarly, electricity produced locally in multi-family houses or non-residential buildings can only be used by multi-family houses or non-residential buildings or sold to the low voltage grid. The grid losses in the high voltage grid are assumed to be 2% and in the low voltage grid 7% and this is defined in the power file.

The district heating commodities are:

- LTH-DH1-GRID (district heat from large scale plants to large scale grid)
- LTH-DH2-GRID (district heat from small scale plants to small scale grid)
- LTH-GRID1-EX (district heat from large scale grid to heat exchanger in end-use sector)
- LTH-GRID2-EX (district heat from small scale grid to heat exchanger in end-use sector)

3.1 Grid fee

A grid fee is added to the low voltage grid, based on Elvia for commercial customers 2021 [13]. The fee is divided in an energy part and one power part and varies between regions as shown in Table 2. The regional variation is based on statistics from NVE [14]. The fee is increased due to increased investments and prices. Based on information from NVE and Elvia, the prices are assumed to increase by 5% until 2030 and the investment costs are assumed to increase by 3% annually. The grid fees are included in the file “Power”. Electricity tax and VAT is defined in the file “Base_Assumptions”.

Table 2 Grid fees per demand sector, region and year

		Energy fee (øre/kWh)					Power fee (NOK/kW/month)				
Year	**Season**	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
Single residential buildings											
2022	Winter	7.0	8.6	8.9	8.2	7.9	360	442	457	419	408
	Spring	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
	Summer	3.9	4.8	5.0	4.5	4.4	66	81	84	77	75
	Fall	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
2030	Winter	7.4	9.0	9.3	8.6	8.3	455	558	578	530	515
	Spring	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
	Summer	4.1	5.0	5.2	4.8	4.6	83	102	106	97	94
	Fall	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
2050	Winter	7.4	9.0	9.3	8.6	8.3	814	1000	1035	949	923
	Spring	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515
	Summer	4.1	5.0	5.2	4.8	4.6	149	183	190	174	169
	Fall	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515
Multifamily buildings											
2022	Winter	7.0	8.6	8.9	8.2	7.9	360	442	457	419	408
	Spring	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
	Summer	3.9	4.8	5.0	4.5	4.4	66	81	84	77	75
	Fall	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
2030	Winter	7.4	9.0	9.3	8.6	8.3	455	558	578	530	515
	Spring	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
	Summer	4.1	5.0	5.2	4.8	4.6	83	102	106	97	94
	Fall	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
2050	Winter	7.4	9.0	9.3	8.6	8.3	814	1000	1035	949	923
	Spring	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515
	Summer	4.1	5.0	5.2	4.8	4.6	149	183	190	174	169
	Fall	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515
Commercial buildings											
2022	Winter	7.0	8.6	8.9	8.2	7.9	360	442	457	419	408
	Spring	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
	Summer	3.9	4.8	5.0	4.5	4.4	66	81	84	77	75
	Fall	3.9	4.8	5.0	4.5	4.4	201	247	255	234	228
2030	Winter	7.4	9.0	9.3	8.6	8.3	455	558	578	530	515
	Spring	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
	Summer	4.1	5.0	5.2	4.8	4.6	83	102	106	97	94
	Fall	4.1	5.0	5.2	4.8	4.6	254	312	323	296	288
2050	Winter	7.4	9.0	9.3	8.6	8.3	814	1000	1035	949	923
	Spring	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515
	Summer	4.1	5.0	5.2	4.8	4.6	149	183	190	174	169
	Fall	4.1	5.0	5.2	4.8	4.6	455	558	578	530	515

The grid fee for electricity produced by PV has been estimated based on discussions with NVE in 2020 concerning future structure of grid tariffs. It is assumed that the firm part of the grid fee will be ca. 80% and that local produced electricity must pay this fee. Due to less distribution losses, ca. 20% of the grid fee is deducted. Not all electricity produced by PV can be used by the producer, but a part will be transformed to the grid and used by other consumers. This part will have the same costs as other electricity. This cost is added as a seasonal flow cost, based on the assumptions in Table 3.

IFE

Table 3 Own consumption of electricity produced by PV

	Residential	Commercial
Winter	96%	100%
Spring	64%	100%
Summer	26%	50%
Fall	48%	100%

3.2 Energy prices

Commodities defined in the fuels file is presented in Table 5 with energy prices for those commodities being an exogenous input to IFE-TIMES-Norway (not produced in the model). Some products can both be produced in Norway and imported, such as biofuels. Emissions are connected to the use of fuel commodities and are included in the fuels file. In the base case, the energy price development is based on information from the power system model EMPIRE [15], while other price development can be defined in scenario files. The values used in base are presented in Table 6.

Table 4 Increase of fossil fuels and biofuels based on EMPIRE[1]

	2020-2025	2025-2030	2030-2035	2035-2040	2040-2045	2045-2050
Gas	8 %	8 %	6 %	3 %	2 %	2 %
Coal	16 %	17 %	6 %	4 %	3 %	3 %
Bio	9 %	9 %	9 %	9 %	9 %	9 %
Oil	12 %	9 %	4 %	6 %	2 %	2 %

Prices of fossil fuels are divided in “production cost”, CO2-tax and other taxes to facilitate analysis of different taxes. The “production cost” is defined in the Fuels-file of IFE-TIMES-Norway, and taxes are defined in the scenario file “Base_Assumptions”. The taxes are based on rates of 2021 [16] and most of the energy production cost is based on Klimakur 2030 [17]. Municipal waste has a disposal fee, resulting in a negative cost of incineration [18].

A general VAT of 25% is added to all costs in single-family houses. Investment costs in the residential sector is with VAT included. VAT of energy carriers is added as a flow delivery cost in the scenario file “Base_Assumptions”. The flow delivery cost also includes a higher delivery cost due to smaller quantities of chips and pellets in the residential sector and in the commercial sector compared to industry. Electricity fee is added as a flow delivery cost in “Taxes”. The fee is 0.546 øre/kWh in industry, 17.7 øre/kWh in commercial and 42.7 øre/kWh in residential (incl. VAT), based on Norwegian taxes 2021.

[1] Fuel prices are provided by EMPIRE in the FlexBuild project and are based on the projections from the EU reference scenario. A 20% reduction in prices are assumed due to technology development.

Table 5 Definitions of fuel commodities and prices in 2018, without VAT

Output Commodity		Cost (NOK/MWh)	Other taxes (NOK/MWh)	Comments/references
BIO-COAL	Biocoal	1082	-	Assumption
BIO-FOR	Biomass-forest	139	-	Statistics Norway
BIO-FUEL	Biomass-based fuel in transport	1234	407	Klimakur 2030; other taxes = “veibruksavgift”
BIO-GAS1	Biogas, cost class I	1000	-	estimated from Clean Carbon report 2019
BIO-GAS2	Biogas, cost class II	2000	-	estimated from Clean Carbon report 2019
BIO-WASTE	Biomass - residues	100	-	Assumption, cheaper than forest
BIO-WOOD	Biomass – wood	50		"selvhogst"
COAL	Coal and coal products (fossil)	273	0	Statistics Norway, industry coal 2019
FOS	Fossil fuel in transport (based on diesel)	675	356	Klimakur 2030; other taxes = “veibruksavgift”
GAS	Gas (based on LPG)	343	0	Klimakur 2030
LNG	Liquid natural gas for maritime	590	173	Klimakur 2030; other taxes = grunnavgift min.olje
MGO	Marine gas oil	440	173	Klimakur 2030; other taxes = grunnavgift min.olje
OIL	Oil (based on light distillate)	541	173	Light fuel oil without VAT; other taxes = grunnavgift min.olje
WASTE	Municipal waste	-273		NVE

Table 6 Emission factors (ton CO2/MWh)

	FOS	OIL	COAL	GAS	WASTE	MGO	LNG
Emissions, t CO2/MWh	0.266	0.266	0.239	0.24	0.173	0.27	0.20

4 Conversion processes and transmission

4.1 Electricity

4.1.1 Hydropower

Hydropower is divided in reservoir and run-of-river technologies and has both existing plants and possibilities for investments in new capacity. Data and development of future potential for hydro power generation is based on information from NVE and is further described below. Table 7 summarizes the generation of existing and new hydropower plants.

Table 7 Hydropower generation in a normal year, TWh/year

	Total generation in existing plants in a normal year (TWh)	Additional generation (TWh)
Mean generation 1981-2010	135.6	
+ new generation 2017-2020	137.7	2.1
+ increased precipitation today	141.2	3.5
+ increased precipitation in 2040	144.0	2.8
+ under construction 2020-2025	146.8	2.8
New potential		
- **Without increased precipitation**	156.7	16.2
- **With increased precipitation**	163.4	6.6+16.2

The existing capacities and generation in a normal year is based on information from NVE in May 2020, and NVEs «Langsiktig kraftmarkedsanalyse 2019-2040» [19]. The normal annual hydropower generation in 2019 is 141 TWh. It is based on mean production in 1981-2010, including increased generation of 3.5 TWh today resulting from increased precipitation (included in 141 TWh).The generation in existing hydropower plants is assumed to increase further by 2.8 TWh (total 6.3 TWh) up to 2040, due to increased precipitation (from today until 2040), see [20].

A total of 2.8 TWh are under construction in the period 2020-2025. The distribution of new capacity per region and reservoir/run-of-river is based on data from NVE. Investments in new hydropower plants that are under construction per March 2020 are included in existing hydropower, based on [21]. In total, this results in 147 TWh hydropower production in 2040 by existing plants (including those under construction in 2020).

The potential for new investments in hydropower is based on information from NVE in March 2018 and is updated with investments in new projects in 2018-2020. In total, existing plants and potential new plants could result in 156.7 TWh, excl. increased precipitation. With increased precipitation of 6.3 TWh in 2040, the total hydropower production can be up to 163 TWh.

The new hydropower plants are divided in two technologies for reservoir power and three for run-of-river. The investment costs are based on LCOE of 0.5-2 NOK/kWh and the potential for the five technologies is added to the model as an activity bound per region.

The operating hours is included in the model as availability per season for reservoir technologies and an annual availability in combination of a share per time slice for run-of-river plants.

For new reservoir plants, the operating hours is reduced since new plants seem to increase the capacity more than the generation. The calculation of availability per season for new reservoir plants, is based on the Lysebotn project [22], where the capacity increased by 75% and the generation by 15%, resulting in an average availability of 65.7% of the original availability for existing reservoir plants.

4.1.1.1 Model input based on EMPS simulations

The operational hydropower input data is calibrated by using simulations by the EMPS power market model [23] that is provided by Sintef Energy. The simulations provided includes weekly weather-year data from 2000 to 2015 on unregulated inflow (GWh) and Norwegian hydropower generation (GWh), for each spot-price region.

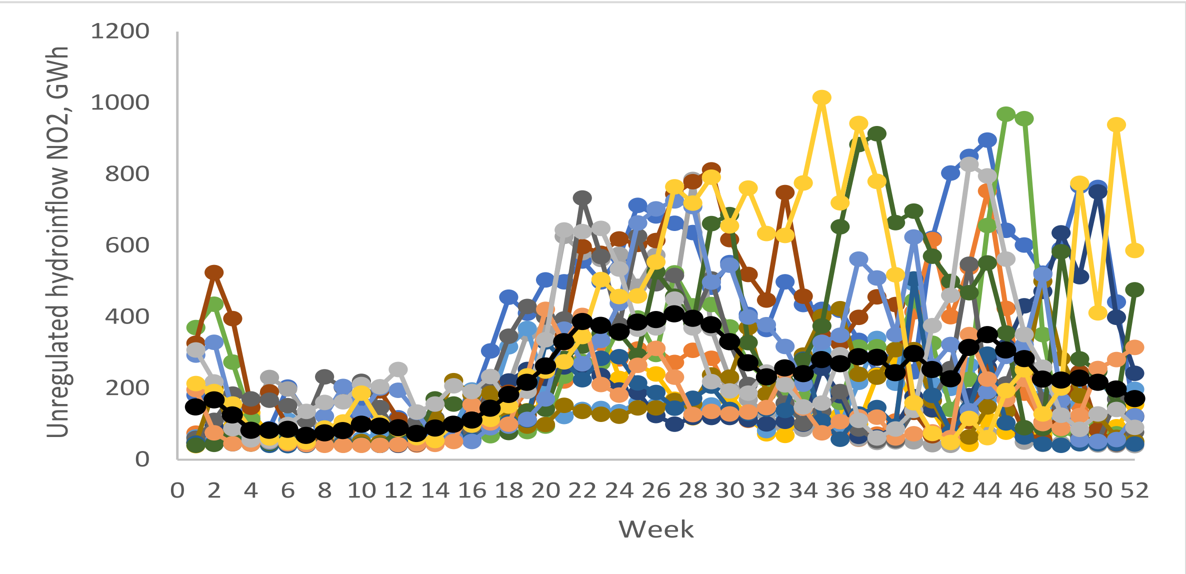


Figure 5 Illustration of unregulated hydro inflow in NO2 for weather years from 2000-2015, where the black line is the average.

First, it is assumed that the unregulated hydro inflow characteristics, as demonstrated in Figure 5, corresponds to the weekly hydropower generation of the run-of the river plants in IFE-TIMES-Norway. The unregulated hydro inflow data is used to map how the unregulated hydropower generation is distributed within the four modelled seasons and to capture the annual variations in the power generation.

In the deterministic model version, weather-dependent operational hours are not considered in the run-of the river hydropower generation. However, unregulated hydro inflow has been used to map how the run-of-generation is distributed throughout the four seasons. The corresponding results and model input are shown in Table 8, and is based on an average of the simulated weather years.

Table 8 Model input on seasonal generation distribution of run-of the river plants in the five spot-price regions

	NO1	NO2	NO3	NO4	NO5
Winter	0.10	0.15	0.20	0.07	0.09
Spring	0.18	0.17	0.17	0.09	0.11
Summer	0.42	0.38	0.31	0.48	0.47
Fall	0.30	0.30	0.33	0.36	0.34
Total	1.00	1.00	1.00	1.00	1.00

For the stochastic model version, it is however assumed that the seasonal distribution and the annual operational hours are weather dependent. The stochastic scenarios, that are designed to capture this weather dependencies, take into account the seasonal generation for all weather years, which is illustrated for NO2 in Figure 6.

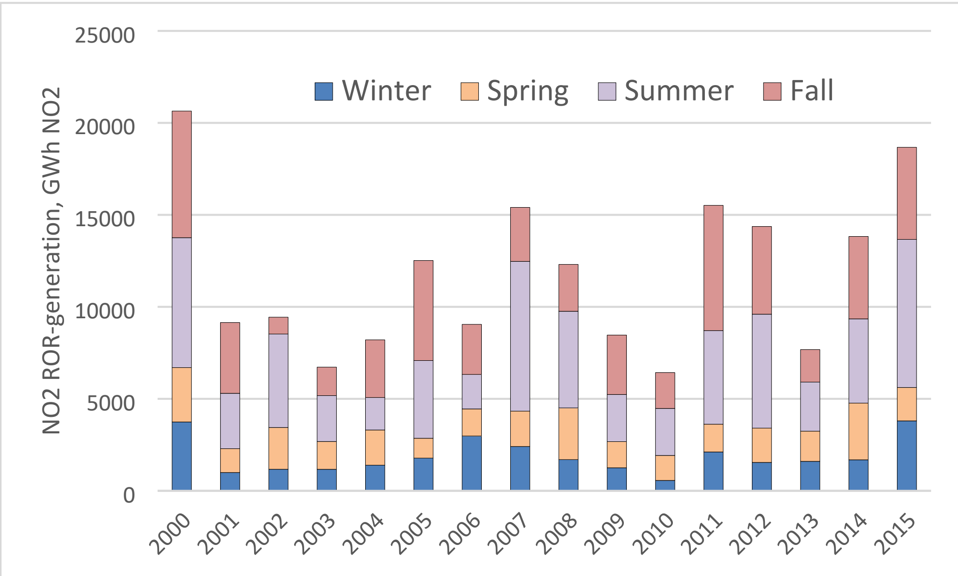


Figure 6 Seasonal ROR generation for NO2 for weather years from 2000 to 2015

Second, it is assumed that the regulated hydropower generation equals the Norwegian power generation minus the unregulated hydro inflow. The corresponding weekly generation characteristics for NO2 is illustrated in Figure 7.

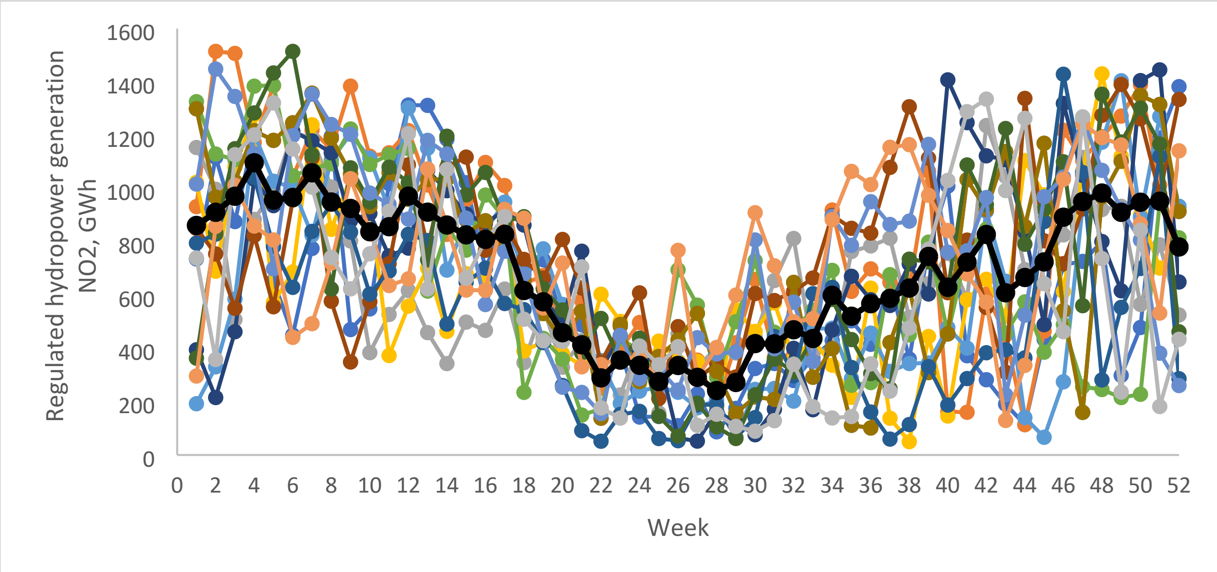


Figure 7 Illustration of regulated hydro power generation in NO2 for weather years from 2000 -2015, where the black line is the average.

For the deterministic model version, this information is used to derive the upper limit for operational hours of the regulated hydropower generation for each spot region, that is based on the average generation over the weather-years. See **Error! Reference source not found.**Table 9 for an overview of the corresponding model inputs. Note, as mentioned above, it is assumed that the operational hours for new regulated hydropower plants are 65.7% of the full load operational hours of the existing plants.

Table 9 Upper limit for operational hours for regulated hydropower generation

	NO1	NO2	NO3	NO4	NO5
Existing	4030	4117	4643	4643	3854
New	2628	2716	3066	3066	2540

For the stochastic model version, it is considered that the operational hours are weather dependent. The stochastic scenarios, which are designed to capture this weather dependencies, take into account the annual generation from regulated plants vary for all weather years, as is illustrated for NO2 in Figure 8.

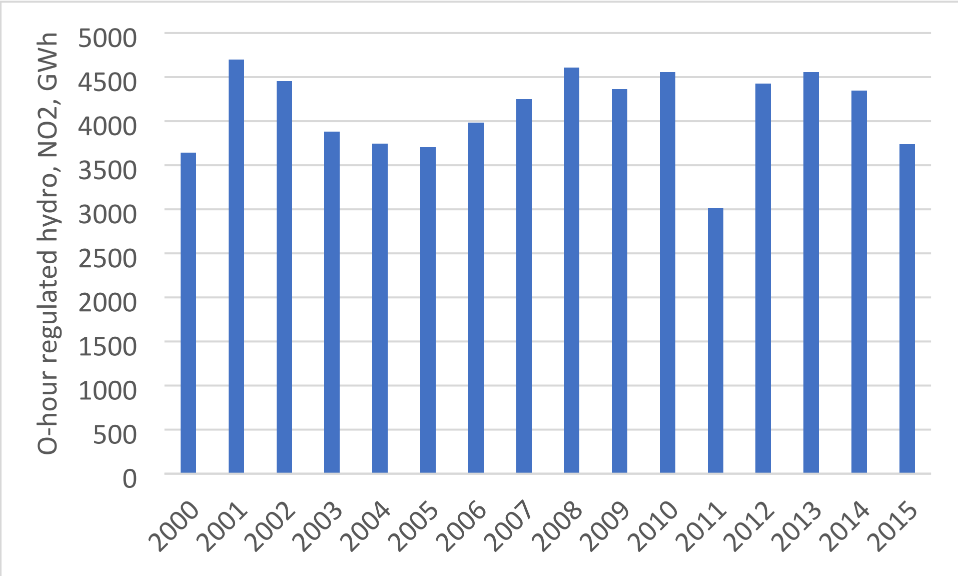


Figure 8 Weather-dependent operational hours of existing regulated hydropower plants for NO2 for weather years from 2000 to 2015

4.1.2 Onshore wind power

Existing wind power plants are included with existing capacity and annual full load hours as presented in Table 10. The data are based on information from the wind power database of NVE [24]. The lifetime for all wind power plants is assumed to be 25 years. The variable operating and maintenance costs are 10 øre/kWh today, declining to 7.6 øre/kWh in 2050, based on [18].

Table 10 Data of existing wind power plants

Region	Full load (hours/year)	Installed capacity 2002-2020 (MW)	Decided to be installed 2021-2022 (MW)
NO1	3 758	224	25
NO2	3 565	1 391	50
NO3	3 469	1 906	345
NO4	3 373	724	50
NO5	3 758	-	40
Total		4 244	510

New wind power plants are modelled as 10 different classes: three levels of investment costs and three levels of full load hours and in addition a high cost/high potential alternative. The investment cost classes in 2020 are:

- Low 5 300 NOK/kW
- Medium 10 600 NOK/kW
- High 17 700 NOK/kW

A technology learning rate of 24% from 2018 to 2035 is used, based on [18]. The investment costs are interpolated between the specified model periods and extrapolated from 2035.

The full load operational time for future wind power plants is divided in three classes:

- high (10% higher than the regional average of today)
- medium (average of today)
- low (10% lower than the regional average of today)

The wind power potential is calculated based on applications for wind power concessions downloaded from the database of NVE [25]. The wind power potential reflects the upper limit for wind power capacity as a total of classes 1-9 in IFE-TIMES-Norway. The potential is 11 TWh as shown by spot price region in Table 11, and is divided equally in the 9 different wind power plant classes. The tenth class reflects additional theoretical potential besides what is applied for in the concession process. The tenth class adds another 22 TWh of potential with the high cost and medium full load hours. Investments in class 1-9 is possible from 2025, while capacity in class 10 is first available from 2035.

Table 11 Wind power potential in a normal year, TWh/year.

	NO1	NO2	NO3	NO4	NO5	Norway
Existing	0.8	4.7	7.1	2.4	0.1	15
Consessions (class 1-9)	0.3	2.3	2.6	5.6	0.1	11
Additional potential (class 10)	0.6	4.7	5.3	11.1	0.2	22
Total	1.7	12	15	19	0.4	48

Reinvestment in wind power plants is another possibility in IFE-TIMES-Norway. The investment cost is assumed to be 20% lower than the average cost of new wind power, due to less costs for infrastructure etc. The possible capacity of reinvestment is restricted to existing wind power plants in 2022.

4.1.3 Offshore wind power

There exists currently no offshore wind power capacity in Norway, and therefore offshore wind is only included as a new investment technology. The technology, defined as EE-WIND_OFF, have different investment costs and technical parameters depending on whether the foundation is bottom-fixed or floating and whether the connection to shore is AC or DC. For bottom-fixed foundations, the Jacket foundation is assumed. The reason for why the electrical current matters on the investment cost of offshore wind parks is because the offshore substation is included. The breakdown for the investment costs in 2020 and 2030 is given in Table 12. The costs are provided by NVE and generalized per kW. Consequently, differences in depth, terrain and wave conditions are not included (with the exception of foundation type). Furthermore, it is assumed a technology learning of 15% by 2050, on both investment costs and operation and maintenance costs, based on IRENA [26].

Table 12 Break-down for the investment costs for offshore wind power in 2020 and 2030 (kNOK/MW).

	2020		2030	
	Bottom-fixed	Floating	Bottom-fixed	Floating
Turbine	11 500	12 000	11 500	12 000
Substructure and foundation	3 500	15 000	2 800	6 750
Installation	1 700	6 000	1 020	3 000
Project development	2 000	4 000	1 400	2 000
Company costs, initiation and liquidation	6 000	9 000	4 500	5 400
Array-cables (procurement)	417	686	355	480
Array-cables (installation)	1 942	2 130	1 651	1 491
DC Offshore substation (procurement)	1 460	1 460	1 314	1 314
DC Offshore substation (installation)	417	417	376	376
AC Offshore substation (procurement)	1 431	1431	1 287	1 287
AC Offshore substation (installation)	417	417	376	376
Total Investment cost (DC)	29 737	50 693	25 555	32 811
Total Investment cost (AC)	29 707	50 663	25 528	32 784

IFE

Six offshore wind areas are currently added as investment opportunities in the model, see

Table 13. The selected areas are based on an impact assessment conducted by the Norwegian water resources and energy directorate (NVE) in 2012 [27], where factors such as ship traffic, landscape and outdoor life, biodiversity, petroleum, fishing, and aviation interests were included in the evaluation. Figure 9 presents a map of all the 15 areas assessed by NVE, where those requiring floating foundations are marked in pink. The selected areas in the model is based on NVE's categorization with regard to recommended opening priority. The potential capacity of the assessed areas is based on estimates from the impact assessment, and it is assumed that investments are available from 2030. The capacity potential sum to 8 GW in 2030, while the upper bound for investments is doubled by 2050, to 16 GW. Production profiles and annual capacity factors for each of the offshore regions are created based on data gathered from Renewables.Ninja for the respective coordinates.

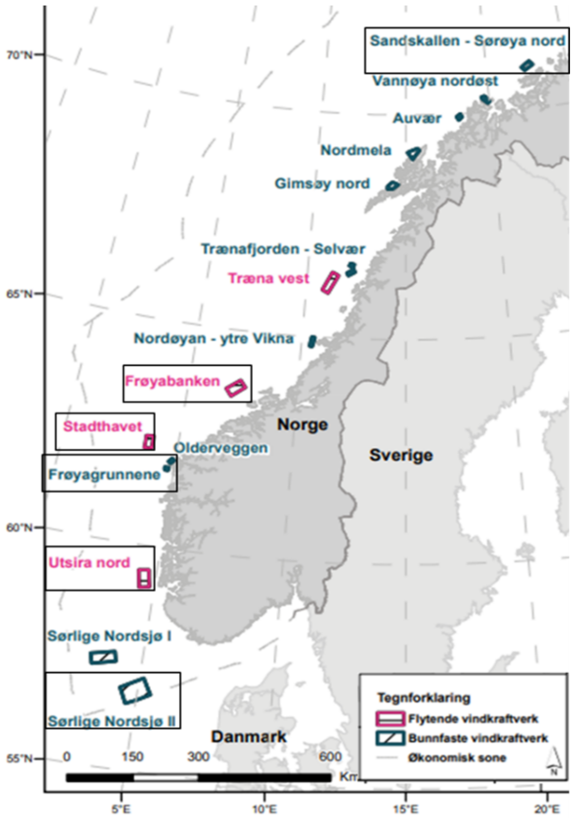


Figure 9 Offshore wind areas assessed by NVE. Framed areas are currently included in the model.

Table 13 Maximum capacity, capacity factor and type of foundation for each offshore wind area.

Offshore area	Capacity	Capacity factor	Foundation
Sandskallen	300	0.39	Bottom fixed
Frøyabanken	1500	0.42	Floating
Stadthavet	1500	0.48	Floating
Frøyagrunnene	200	0.48	Bottom fixed
Utsira Nord	1500	0.47	Floating
Sørlige Nordsjø II	3000	0.57	Bottom fixed

Due to locational restrictions, it is assumed that only Utsira Nord and Sørlige Nordsjø II can export electricity to Europe. Connections to the UK, Western Denmark, Germany and the Netherlands are currently included. For the remaining areas, the model can only invest in one direct connection to the adjacent spot region in Norway, a radial connection. Several connections can later be established, such that the model chooses which spot area it is most beneficial to connect the offshore wind park to. The capacity of the trade cables is limited to the capacity of the respective offshore wind park, as presented in

Table 13. The investment costs for export cables are calculated based on the estimated kilometer distance to the various connection points. The availability factor of the offshore cables is assumed to be the same as the connection from Norwegian shore to the respective country/region. Investment cost for the offshore wind park and the respective export cables in 2030 is given in Table 14.

Table 14 Investment cost of wind park and export cable in 2030 for the respective trade connection.

Offshore area	Export connection	Investment cost park 2030 [kNOK/MW]	Investment cost trade cable 2030 [kNOK/MW]
Sandskallen	NO4	25 528	4 360
Frøyabanken	NO3	32 784	4 795
Stadthavet	NO3	32 784	5 730
Frøyagrunnene	NO3	25 528	3 965
Utsira Nord	NO5	32 784	2 268
	DK1		13 519
	UK		18 193
	DE		22 244
	NL		21 932
Sørlige Nordsjø II	NO2	25 555	4 596
	DK1		4 990
	UK		7 090
	DE		6 959
	NL		6 696

As offshore wind parks are located outside the Norwegian coast, each park has been modelled as a separate region. This is accomplished by creating a “Book region”, including all the offshore locations. The benefits of having a separate “book” for the offshore regions is that definitions given for “AllRegions” in the original model does not apply for the offshore regions. This is convenient as the offshore model should not have any other technologies except for the offshore wind turbines, and no demand. The definition of the technologies for the offshore regions is defined in a separate Base Template file “VT_Offshore_Power”.

As offshore wind parks are expensive, an additional restriction on the trade is necessary to prevent the model from using the offshore cables to only trade electricity between countries, without investing in wind turbines. A user constraint is therefore created, restricting export from the offshore region to be less than the wind production for all hours. Consequently, if the wind turbines do not produce, there will be no trade on the cables. A limitation of this constraint is that it disables the possibility of a hybrid connection, in which redundant capacity is used to trade between the countries, whenever wind production is low. This is however a difficult constraint to add without using binary variables, which would increase the solution time of the model considerably. Nevertheless, the topic will be addressed in further work.

Lastly, a line was added in the SysSettings file to allow for negative variable cost components in the objective function. This is a special case that occur when adding regions without any demand to the model. As the offshore regions only produce electricity, their contribution to the objective function will be negative as the revenue exceeds the cost. As the OBJVAR variables is non-negative by default, the model would choose to export the electricity through another region having variable costs in order to realize the revenues. To avoid this, the line in Table 15 was added.

Table 15 Line added in SysSettings to allow for negative variable cost components in the objective function.

LimType	Attribute	UC_N	Allregions
N	UC_RHS	OBJVAR	-1

4.1.4 PV

Photovoltaic electricity production is included as existing and new technologies in single-family houses, multi-family houses, non-residential buildings, light industry buildings and agriculture. PV parks are included as new technology with a start year of 2100 and no upper potential. When the start year is 2100, it means that the PV parks are not included in the analysis. However, in specific scenarios, the start year can be changed to include PV parks. The existing capacity is calculated until the end of 2020 and is 48 MW in the residential sector and 79 MW in the commercial sector [28]. No existing capacity in light industry buildings or agriculture is added.

The investment costs in 2020 are based on Multiconsult [29]. The cost interval is divided in three with an assumption of medium cost being an average of low and high. The cost of PV in single-family houses includes VAT 25%. The future costs are calculated based on the development of large-scale solar PV presented by IEA in [30]. Investment costs are reduced by 42% from 2020 to 2030 and by 57% from 2020 to 2050. The Fixed operation and maintenance cost is calculated as 0.5% of investment cost, based on NVE [31]. An overview of technology data for PV installations is presented in Table 16.

Table 16 Technology data for PV installations

	Investment cost			Operation and maintenance cost		Lifetime
	NOK/kW			NOK/kW		years
	2018	**2030**	**2050**	**2018**	**2030-**	
Single-family houses						30
Low cost	14 000	8 200	6 000	70	41	
Medium cost	16 000	9 300	6 900	80	47	
High cost	18 000	10 500	7 700	90	53	
Commercial and Multi-family houses						30
Low cost	7 000	4 100	3 000	35	21	
Medium cost	9 500	5 500	4 100	48	28	
High cost	12 000	7 000	5 200	60	35	
Park	6 000	3 000		30	15	30

PV production profiles are calculated based on annual load profiles from renewables Ninja [32, 33]. Data is based on satellite photos from the period 2000-2018 and the cities Tromsø, Bergen, Trondheim, Kristiansand and Oslo represent the five regions of IFE-TIMES-Norway. Profiles for PV installed in the residential and commercial sector are calculated for 24 hours of a typical day in the four seasons. The tilt is assumed to be 30° south for PV-plants in single-family houses and 10°west/east for PV in multi-family houses and non-residential buildings.

A rough estimate of the maximum potential in buildings is given in Table 17. The potential is based on calculations made by Sintef Community in the FlexBuild project [34]. This estimate is uncertain and is in process to be updated.

Table 17 Region specific data of PV

	Annual share of full load hours		Potential (MW)			
	Single-family houses	Multi-family houses, non-residential buildings, industry	Single-family houses	Multi-family houses	Non-residential buildings	Industry and agriculture
NO1	0.11	0.09	4 428	605	3 192	2898
NO2	0.12	0.10	3 075	165	1 824	1656
NO3	0.11	0.09	1 845	132	1 064	966
NO4	0.09	0.07	1 476	66	684	621
NO5	0.09	0.08	1 476	132	836	759
Norway			12 300	1 100	7 600	6 900

As describe in section 3, not all electricity produced by PV will be used by the producer, but a part will be sold to the grid and used by other consumers. This part will have the same costs as other electricity. This cost is added as a seasonal flow cost, based on the assumptions in Table 3.

4.1.5 Electricity storage

The electricity storage technology is included as a new technology in residential and non-residential buildings, as well as utility-scale storage in the grid. The storage technology represents a micro- to small scale battery suitable for increasing self-consumption within a day-night cycle. The battery storage is modelled as a *DAYNITE* level storage, which is assumed to only be able to store electricity over a day-night cycle. The C-rate of a battery storage is taken into account with attribute *NCAP_AFC*. The relation between attribute *NCAP_AFC* and C-rate is presented in Eq. (1)

$$NCAP\_AFC{\sim}DAYNITE = \frac{{C_{RATE}}^{-1}}{24 * STG\_EFF}. \qquad (1)$$

Electricity storage related techno-economic data is presented in Table 18. Investment costs are based on NREL [35], using the linear relationship equation between energy costs and power costs, as given by Eq. (2). In the base case, the mid projection by NREL is assumed.

$$Total\ cost\ (\$/kWh) = Energy\ cost\ (\$/kWh) + Power\ cost/\ duration(hr) \qquad (2)$$

Fixed O&M costs are assumed to be 10% of investment cost. For single family houses, the investment cost is 25% higher due to value added tax (VAT). Due to the use of attribute *NCAP_AFC*, the capacity of a battery storage describes its nominal maximum output. Therefore, if the investment cost is given in unit of energy, it must be converted to unit of capacity (e.g., kNOK/GWh/a) using Eq. (3).

$$INVCOST(kNOK/GWh/a) = \frac{INVCOST(kNOK/GWh) * NCAP\_AFC * 24}{8760}. \tag{3}$$

In VEDA-TIMES results tab, the nominal maximum output of a battery storage (i.e., *VAR_Cap*) can be converted to storage capacity in terms of energy with Eq. (4)

$$\frac{VAR\_Cap * NCAP\_AFC * 24}{8760}. \tag{4}$$

The reader should note that in Eq. (2) and (3), it is assumed that *PRC_CAPACT = 1*. Therefore, when attribute *PRC_CAPACT ≠ 1*, it needs to be added as a multiplier.

Table 18. Electricity storage technology data.

		Buildings sector	Utility scale
Technical lifetime (year)		15	15
Investment cost (kNOK2016/GWh)[3]	2020	6 750 250	3 484 000
	2030	4 790 500	2 177 500
	2040	4 398 550	1 916 200
	2050	4 006 600	1 654 900
Storage efficiency (%)		90	82
Availability factor, storage capacity (%)		2[1]	10
Availability factor, bound on input/output flows (%)		100	100
Max. Storage cycles (# of cycles)		4500[2]	4500
Capacity to activity		1	1

[1] 2% corresponds to 30 minutes of maximum net output (considering storage efficiency), i.e., C-rate of 2. 10% correspond to c-rate of 0.5. This attribute is assigned to commodity group "ACT".
[2] Maximum number of cycles over the full lifetime of storage process. Source: https://www.psi.ch/sites/default/files/import/eem/PublicationsTabelle/2014-STEM-PSI-Bericht-14-06.pdf
[3] Source: [35]. Given as kNOK/GWh, needs to be converted to kNOK/GWh/a using Eq. (3). Building sector cost for single-family houses is 25% higher due to VAT.

4.1.6 Transmission grid

Existing transmission capacity within Norway and to European countries are given in Table 19 and Figure 10

Table 20. In addition, the model allows for investments and expansion of both national and international transmission capacities between the regions. In Table 20, the assumed investment cost of new capacity is presented, where the investment cost varies due to the distance and technologies (cable vs. lines), based on project specific data [36-40]. New international transmission capacity to European countries is based on ENTSO-E's Ten-year network development plan 2020 [41], see Table

21. For trade cables between internal regions in Norway, we allow for a 20% increase in capacity. The estimate is uncertain and will be updated based on dialogue with the TSO. To compensate for the coarse representation of the power flow in IFE-TIMES-Norway, availability factors are included on the cables within Norway and to Europe. The factor limits the total flow on the line but is not specified for the direction of the flow. For international trade cables, the factor is based on input from the European power model, EMPIRE. For national trade cables, the factor is based on historical flow values. As new transmission cables typically take 10 years to construct and commission, it is assumed that no new investments will be available before 2030. Trade cables from offshore wind regions are described in Section 4.1.3.

Table 19 Existing transmission capacity in 2020 (MW)

	NO1	NO2	NO3	NO4	NO5
NO1		3500	500		3900
NO2	3500				600
NO3	500			1200	500
NO4			1200		
NO5	3900	600	500		
SE1				700	
SE2			1000	300	
SE3	2145				
DK1		1632			
RUS					56
DE		1400			
NL		723			
UK		1400			

IFE

Table 20 Investment cost for new transmission capacity (NOK/kW)

	NO1	NO2	NO3	NO4	NO5
NO1		841	2049		1216
NO2	841				1265
NO3	2049			3807	1195
NO4			3807		
NO5	1216	1265	1195		
SE3	1264				
DK1		5714			
DE		8750			
NL		8570			
UK		14285			14285

Table 21 Upper limit for new transmission capacity (MW)

	NO1	NO2	NO3	NO4	NO5
NO1		700	100		780
NO2	700				120
NO3	100			240	100
NO4			240		
NO5	780	120	100		
SE3	1500				
DK1		2000			
DE		2000			
NL		4000			
UK		2000			1400

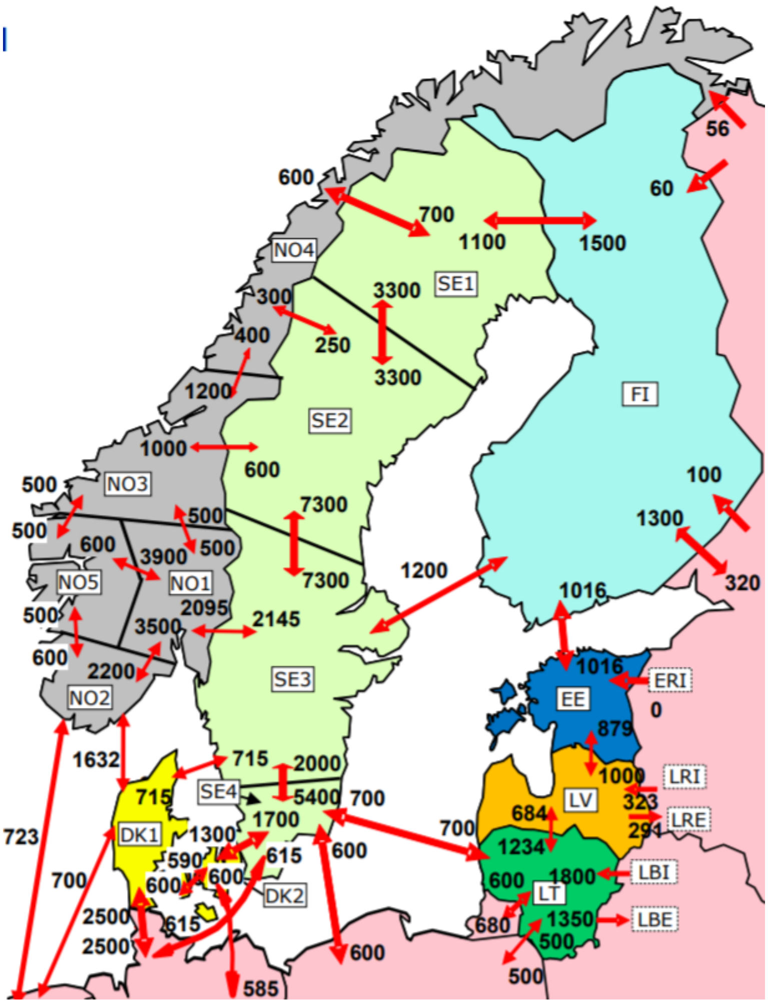


Figure 10 Net transmission capacities between regions from 2022, MW [42]

4.1.7 Electricity trade

IFE-TIMES-Norway needs exogenous input of electricity prices for countries with transmission capacity to Norway. Electricity trade prices are typically project specific, but a set of prices are included in the Base Assumptions-file. The prices for the base year are the average prices from 2018, from NordPool [43] and entso-e [44]. The future prices are a result from NVE, based on their analyses "Langsiktig Kraftmarkedsanalsye 2020-2040" [45]. The average power prices are presented in Table 22. Figure 11 shows an example of the prices for export to Germany. Linear interpolation is used to estimate electricity prices between two given years until 2040. After 2040, the exogenous electricity prices are assumed to remain constant.

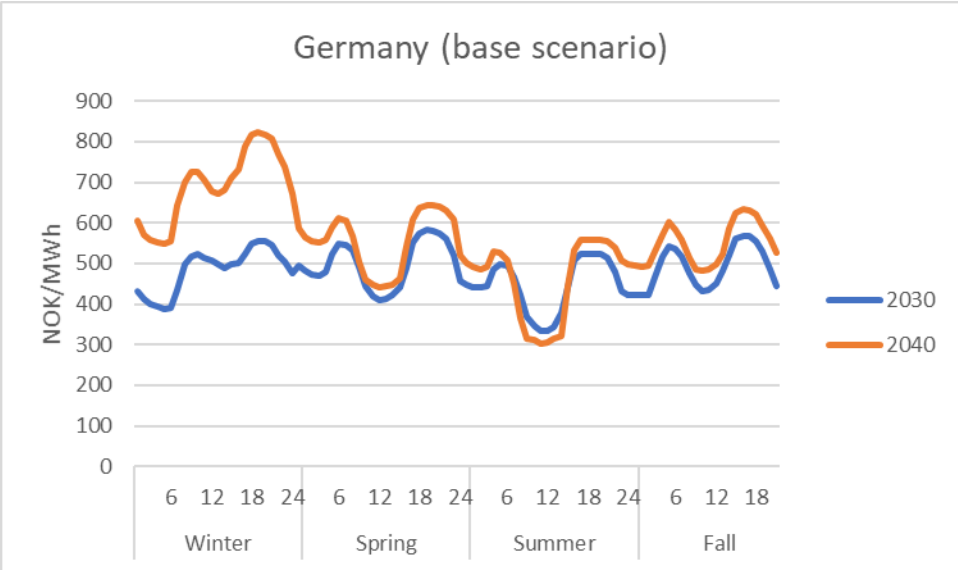


Figure 11 Electricity prices for export to Germany in base scenario in 2030 and in 2040.

Table 22 Average power trade prices, NOK/MWh [45]

Year	Sweden	Finland	Denmark	Germany	The Netherlands	UK
2022	370	370	350	440	440	540
2025	420	410	430	490	470	560
2030	370	350	470	470	450	480
2040	410	410	440	460	460	510

4.2 District heating

4.2.1 Background

District heating has been modelled as one system with several heating plant alternatives in each electricity spot area. To better cover the diversative of different district heating systems, two sizes are introduced – large and small/local district heating grids. This facilitates the incorporation of different specific investment costs of large and small systems and assumptions of technologies to be available for local systems.

In a model like IFE-TIMES-Norway, all buildings have the same costs and availability to use different technologies, if no restrictions are applied. Therefore, a market share is often used, to better represent the actual possibilities and/or different costs or efficiencies of various technologies.

4.2.2 Statistics

Use of energy for production of heat in district heating plants has increased from 0.5 TWh in 1985 to 8 TWh in 2019, see Figure 12 [46]. In addition to energy used for heat production, 0.7 TWh was used for electricity production and 0.8 TWh was cooled to air. Use of district heating was in total 6.6 TWh in 2019, including grid losses. End-use of district heating was in total 5.9 TWh, and of this, commercial buildings used 3.4 TWh, dwellings 1.5 TWh and industry 0.8 TWh, see Figure 13.

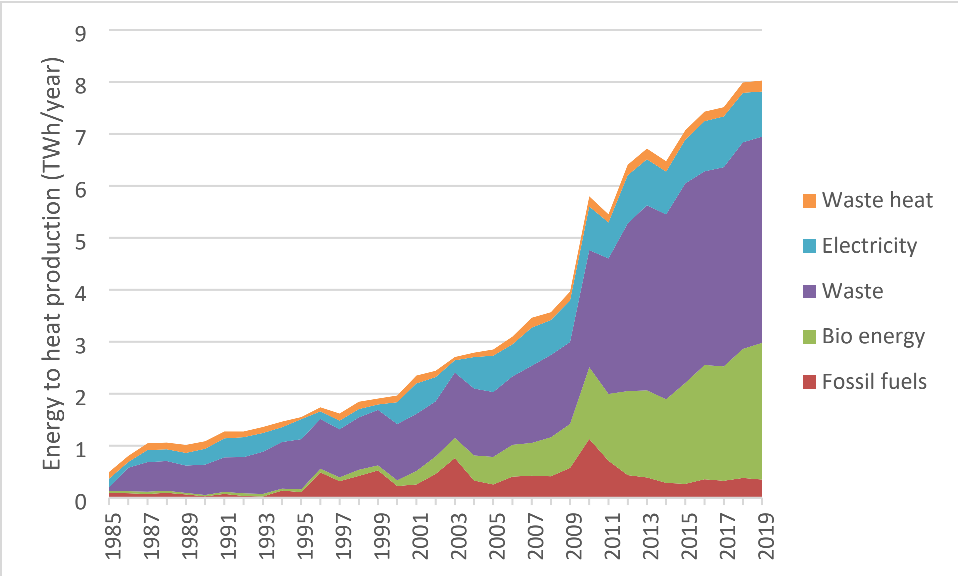


Figure 12 Energy used for heat production in district heating plants 1985-2019, TWh/year

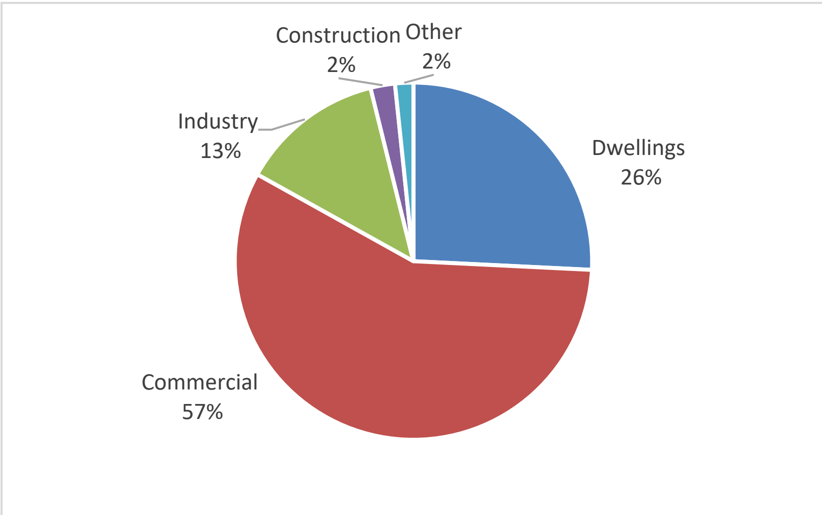


Figure 13 Use of district heating per end-use sector in 2019

Information on a plant level can be found at fjernkontrollen.no, were most of the district heating companies report data. Most of district heating is produced in market spot price area NO1, 3.3 TWh in 2019, and the second largest area is NO3, see Figure 14.

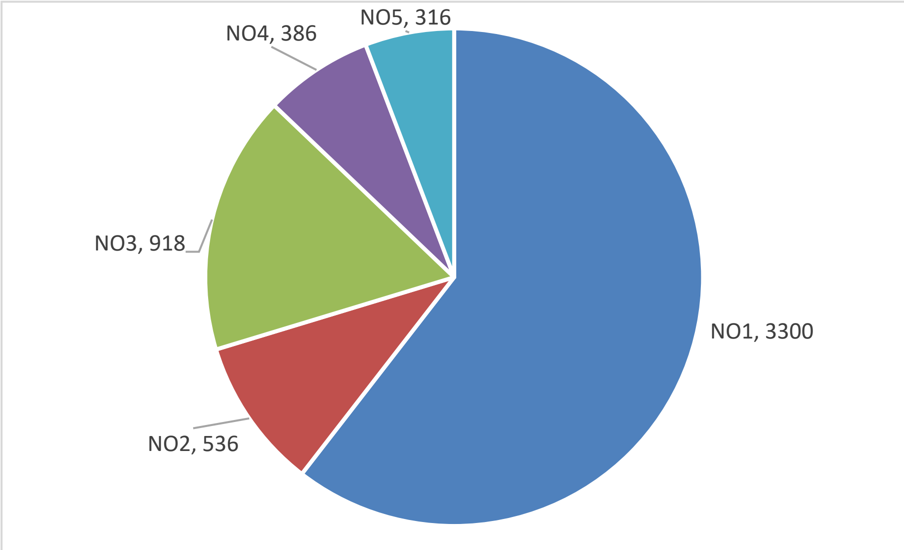


Figure 14 District heating production per market spot price area in 2019 [47], GWh/year

Only one site produces more than 1 TWh/year (Oslo) and two more produce more than 300 GWh/year (Trondheim and Bergen). The number of plants delivering 100-300 GWh/year was 8 in 2019 (Hamar, Tromsø, Kristiansand, Ålesund, Lillestrøm, Fornebu, Forus, Drammen). In total 11 plants produce 3.8 TWh/year. If it is assumed that only smaller plants do not report to fjernkontrollen.no, the production from plants with an annual production less than 100 GWh/year can be estimated to 2.8 TWh produced at 90-100 plants. This is used to define large and small/local district heating systems in the IFE-TIMES-Norway model, in which large grids produce more than 100 GWh/year and small/local district heating systems produce less than 100 GWh/year.

4.2.3 Estimate of maximum potential for district heating

One way of estimating a maximum potential for district heating is to base it on an assumption that all commercial buildings and dwellings in areas with high enough density can be connected to a district heating system (large or small/local). Statistics Norway publish data on people living in "tettbygde strøk" (densely populated areas) and the definition of these areas are "at least 200 people live in an area of houses with less than 50 m apart". With this definition 18% of people in Norway live in areas that cannot be connected to local or large district heating systems. The share differs in the five Norwegian spot price regions, see Table 23.

Table 23 Population in densely and sparsely populated areas

	Spot price area	Densely populated area	Sparsely populated area
East	NO1	86 %	14 %
South	NO2	84 %	16 %
Middle	NO3	74 %	26 %
North	NO4	72 %	28 %
West	NO5	80 %	20 %
Norway		82 %	18 %

Another assumption made, based on information from major Norwegian district heating companies, is that single-family houses cannot be connected to a district heating system. This is a simplification and is not true in all cases, but as a model assumption it is justified since it often not is profitable to connect single-family dwellings to a district heating grid. On the other hand, it is assumed that all multifamily houses within densely populated areas are possible to connect to a heat grid, but this is probably a minor overestimation.

Buildings with a water borne heating system can be connected to a district heating grid. In principle, buildings with point source heating could also be connected if they invest in a water borne heating system first, but as this is considered as a very large investment often done of other reasons than pure techno-economical, it is not included as a possibility. The basic assumption is that the share of water borne heating is 58% in existing commercial buildings and 90% in new buildings, 38% in existing multifamily houses and 88% in new multifamily houses. In single-family houses the share of water borne heating is 12% in both existing and new dwellings, but this has no influence on the use of district heating, since it is assumed that they cannot be connected to a district heating grid.

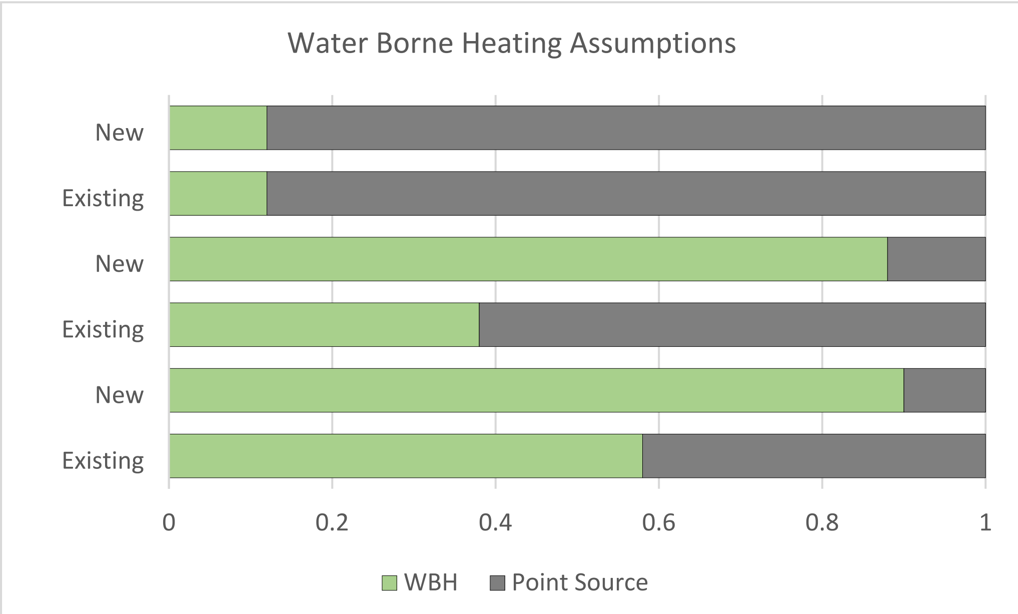


Figure 15 Share of water borne heating (WBH) and point source heating in buildings

Definition of large and small district heating systems is based on that "large" systems are applicable in cities and "small/local" systems otherwise. The estimate of people living in "cities" is not well founded but based on different statistics and knowledge of district heating grids of today. The estimate is calculated using the number of inhabitants in the centre of cities divided by total inhabitants of the region, see resulting share in Table 24.

Table 24 Share of large district heating systems per electricity price area

	Electricity price area	mill. Persons in «cities»	Share living in «cities»
East	NO1	1.47	65 %
South	NO2	0.61	50 %
Middle	NO3	0.28	38 %

North	NO4	0.18	37 %
West	NO5	0.30	47 %
Norway		2.83	53 %

The maximum share of connections to large or local district heating grids per type of dwelling and commercial building is presented in Table 25. In this table, "buildings" refer to both multi-family houses and commercial buildings. The share is calculated by the "share living in cities" and the share of "densely populated area", e.g., for NO1 the share of buildings connected to large district heating grids is 86 % * 65 % = 56 %.

Table 25 Share of maximum connection to large and small/local district heating grids per region

	El. price area	Single-family houses	Buildings with point source heating	Buildings with waterborne heating	
				Large	Local
East	NO1	0%	0%	56 %	30 %
South	NO2	0%	0%	42 %	42 %
Middle	NO3	0%	0%	28 %	46 %
North	NO4	0%	0%	27 %	46 %
West	NO5	0%	0%	38 %	42 %
Norway		0%	0%	44 %	38 %

An illustration of the possible share of small, large and no district heating system is presented in Figure 16.

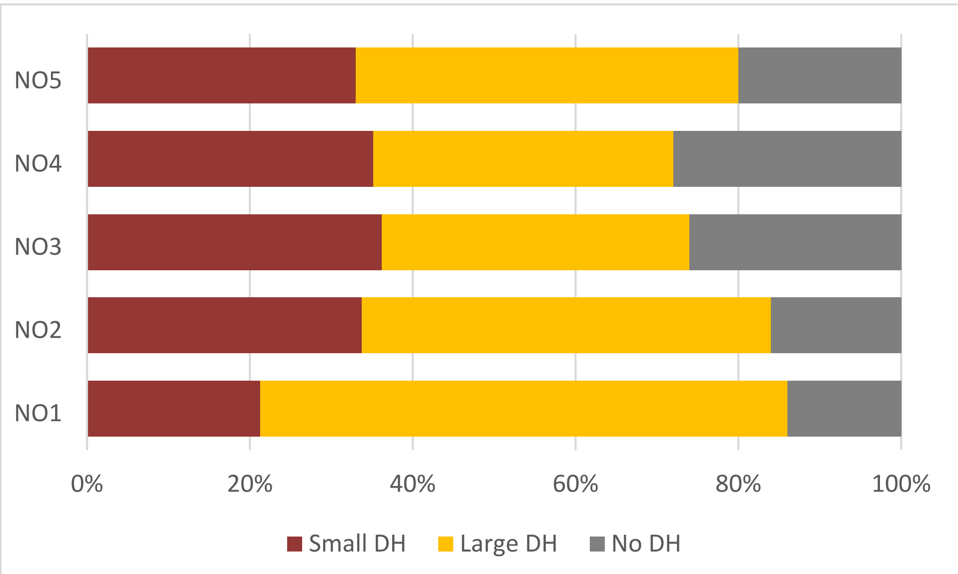


Figure 16 Share of small, large and no district heating systems per market spot price area

With these possible maximum shares for connection with local or large district heating grids, a total upper potential for commercial buildings and dwellings can be calculated to 10-11 TWh in 2030–2050.

Table 26 Maximum potential of use of large and small/local district heating in 2030 (GWh/year)

	El. price area	Single-family houses	Buildings with point source heating	Multi-family houses with central heating		Commercial buildings with central heating	
				Large	Local	Large	Local
East	NO1	0	0	660	360	2 150	1 170
South	NO2	0	0	280	280	1 040	1 030
Middle	NO3	0	0	110	180	410	670
North	NO4	0	0	60	110	280	480
West	NO5	0	0	100	110	400	450
Norway		0	0	1 210	1 040	4 270	3 800

In Figure 17, the use of district heating in 2019 is compared with the maximum potential in 2030 based on the above calculations. The potential in industry, construction and others is assumed to increase at a similar rate as in commercial buildings. In total, the potential in 2030 will be 13 TWh compared to the use of district heating in 2019 of almost 6 TWh.

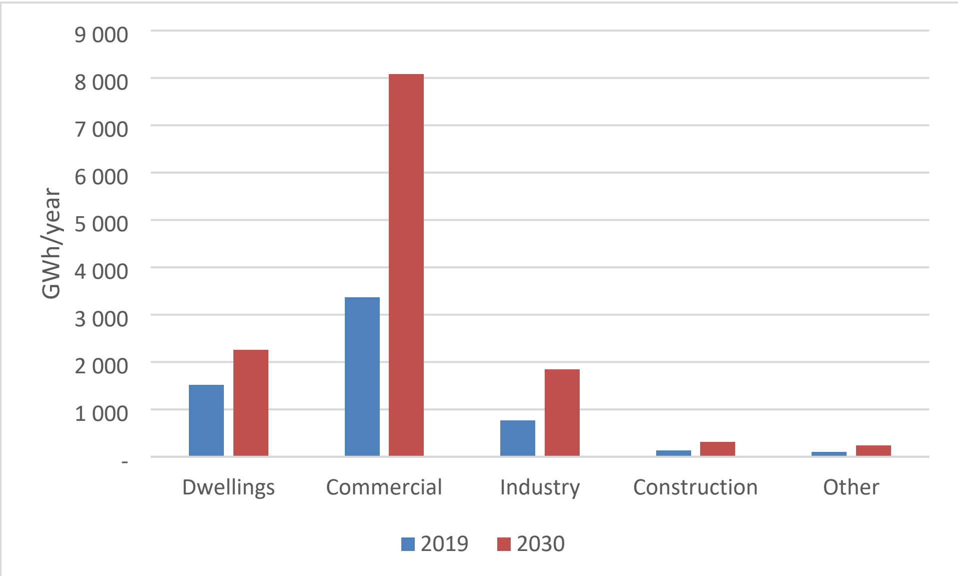


Figure 17 Use of district heating in 2019 and calculated maximum potential in 2030 per end-use sector (GWh/year)

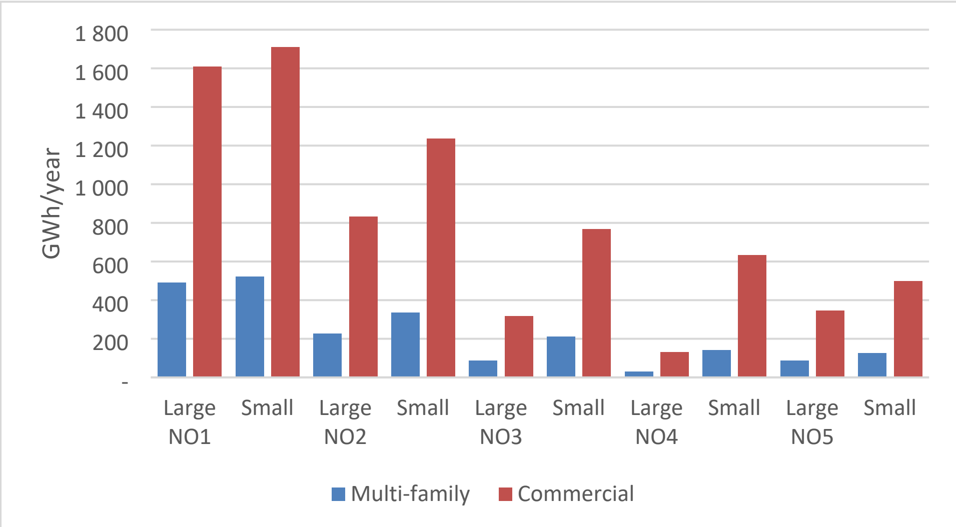


Figure 18 Calculated maximum potential in 2030 of large- and small-scale district heating per market spot price area

4.2.4 Heating technologies

District heating plants produces heat distributed to a district heat grid. Heat from the grid is input to district heat exchangers within the end-use sectors building and industry. The different types of existing and potential new investments in district heating boilers and CHP are presented in Table 27, along with respective input data. Cost of CHP due to technology learning is 4% reduced in 2035, based on [18].

Table 27 District heating plants and grid

Technology	Investment cost 2018 (NOK/kW)	Market share (maximum)	Efficiency	Life time (years)
Fossil boiler **- large** **- small**	 763 963		 92% 92%	 20 20
Waste boiler (large)	25 310			20
Biomass boiler **- large (wet fuel)** **- small (dry fuel)**	 6613 5883		 89% 90%	 20 20
Electric boiler **- large** **- small**	 533 790		 98% 98%	 20 20
Heat pump **- large** **- small**	 9099 9179	 50% 50%	 2.8 2.8	 20 20
Heat pump using waste heat **- large** **- small**	5906 6776		5 5	20 20
Waste CHP (power output)	133 000		4.0	20
Grid **- large** **- small**	 3159 3159		 89% 89%	 60 60

Municipal waste can only be used in large district heating plants, and it is assumed that the volumes of today will be constant until 2050. The municipal waste must be used since it is not allowed to deposit waste anymore.

Heat delivered by heat pumps using waste heat is restricted by the waste heat potential. In IFE-TIMES-Norway, it is assumed that this technology can deliver 250 GWh/year of heat for each region NO1-NO4, with 50 GWh/year for NO5 in 2020. The potential is expected to double by 2030, reaching 2.1 TWh for all of Norway.

CCS

CCS in waste incineration in district heating plants with CHP is included as a possibility in SubRES files: SubRES_CCS and SubRES_CCS_Trans, with region specific data in the Trans-file. In addition, the Scen_CCS file is needed to force in use of waste incineration plants and avoid double counting of stock. See description in section 5.1.3.

4.2.5 Thermal storage in district heating

Thermal storage in district heating has been modelled using large thermal storage tanks, typically sized around 3000 m3. Similar to the battery storage technology, thermal storage is modelled as a DAYNITE level storage, meaning it can only store heat over a day-night cycle. Seasonal storage is possible for large district heating systems.

Two daily storage technologies are added, one with 4 hours storage capacity and one with 12 hours capacity, both for large scale district heating grids and for small/local district heating grids. The same parameters apply for both storage technologies, but the input and output commodities differ. Information about technology characteristics and costs can be found in Table 28. A round trip storage efficiency of 98% is assumed, with a 0.2% energy loss per day during storage. The seasonal storage is based on a storage capacity of 500 hours, the efficiency is 80% and the daily storage loss 0.2%.

Table 28 Parameters and cost for thermal storage tanks in district heating [48].

	Investment cost (kNOK/GWh)	Fixed O&M (kNOK/GWh)	Efficiency (%)	Storage loss (%/day)	Lifetime (years)	NCAP_AFC
Daily storage, 4 hours	30 000	86	98 %	0.2 %	40	0.17
Daily storage, 12 hours	30 000	86	98 %	0.2 %	40	0.51
Seasonal storage	10 000	29	80 %	0.2 %	40	0.29

4.3 Bio energy

Bio energy can be imported as bio coal, biofuel, biomass or bio wood, but limitations are added in the base case. The model includes production of bio chips/pellets, biofuel and bio coal from biomass.

In the fuels file, regional limitations of wood resources are included based on the use of today. A total of 5.9 TWh/year is available at a low cost, corresponding to the actual use that to a large extent is self-harvesting.

Biomass can be used as raw material in the wood industry or as energy resources, see Figure 19. The energy resources include use as chips/pellets in heating plants, conversion to biofuel or conversion to bio coal. The technology data for conversion from biomass to biofuel or bio coal is based on information from NVE [17] and presented in Table 29.

Table 29 Technology data for conversion of biomass to biofuel or bio coal

	Efficiency	Lifetime (years)	Investment cost (NOK/MW)	Fixed O&M cost (NOK/MW)	Variable O&M cost (NOK/GWh)
Biofuel	58%	30	86 000	2500	250
Bio coal	25%	30	10 000		41

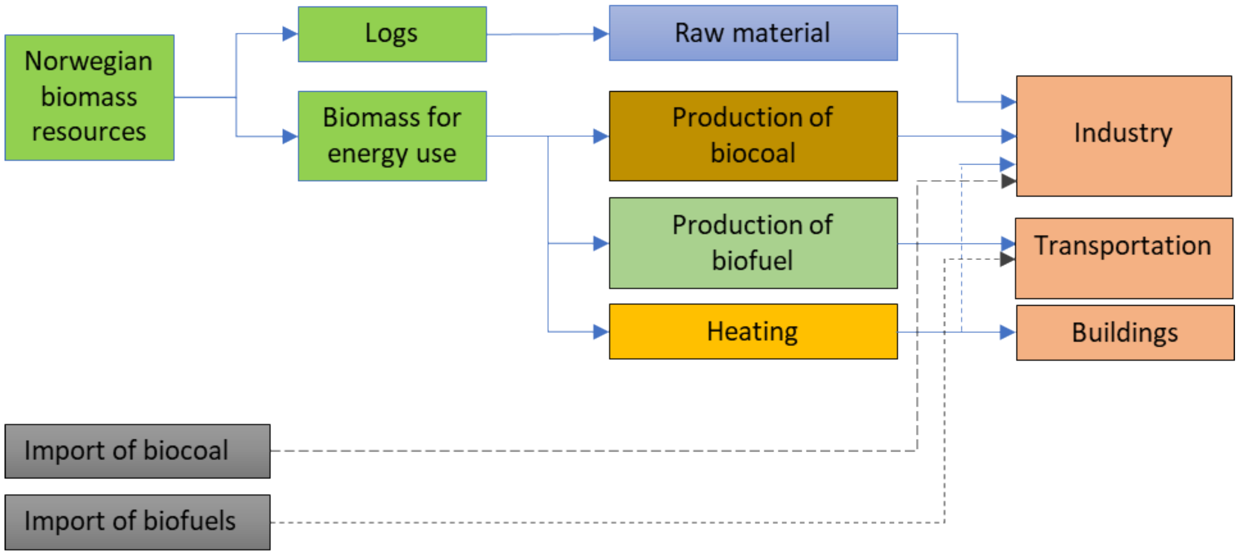


Figure 19 Schematic overview of biomass resources, conversion processes and end-use

Various bioenergy products can be produced from Norwegian raw materials or be imported. Consumption of bioenergy resources and possible future potential is estimated and graphically presented in Figure 20. Other bioenergy resources may also be possible to use as raw material for production of biofuels, but here the focus is on solid biomass. In the future, it may be possible to use marine biological resources for production of various bioenergy products, but this has not been considered here.

Norway has large biomass resources related to the forest. About 11 mill. m^3 timber was felled for sale in 2018 [49], approx. 22 TWh, but there is potential to increase it to approx. 31 TWh within what is called the balance quantity and is sustainable felling. The annual forest growth is estimated at approx. 50 TWh.

When timber is felled, there are usually biomass resources left on the felling field that can be used for energy production (GROT) with an estimated energy content of 6 TWh/ year based on current felling. Another resource that can be used for energy production is wood waste (recycled chips), which is estimated at 3 TWh. Wood consumption in households was 5.6 TWh in 2018 according to Statistics Norway (5.1 TWh in 2019). In total, possible Norwegian bioenergy resources from solid biomass are estimated to 46 TWh (incl. biomass used as raw material; 31+6+3+5.6=45.6).

Today's consumption of solid biomass as raw material in the wood industry (lumber, paper, fibreboards, etc.) is estimated to about 11 TWh. Combustion of biomass in boilers in district heating plants, industry and buildings was 2.7 TWh in 2018 and wood consumption in households was 5.6 TWh [50]. A total of 7 TWh was exported and 1 TWh was imported [49]. Industrial use of charcoal was approx. 0.5 TWh. In total, the current consumption of solid biomass is about 26 TWh.

In 2018, 4.4 TWh of biofuel and 48 TWh of fossil fuels (diesel, petrol, gas) were used. If this amount were to be produced from solid biomass with an efficiency of 58% biofuel per biomass, the need would be 91 TWh biomass.

Today's use of biogas is approx. 0.2 TWh and the potential for increased biogas production in Norway is estimated to 2.7 TWh. A realistic potential is estimated at about 2 TWh and a theoretical one at about 4 TWh in [51]. In [52] the potential for biogas is 4 TWh in 2020. Klimakur 2030 states the potential for biogas to be from 2.3 to 5 TWh / year [17], based on a study by [53]. This study is the most recently and detailed at is used to divide the potential in two price classes: 1.2 TWh at a price of 1 NOK/kWh and 1.5 TWh at a price of 2 NOK/kWh.

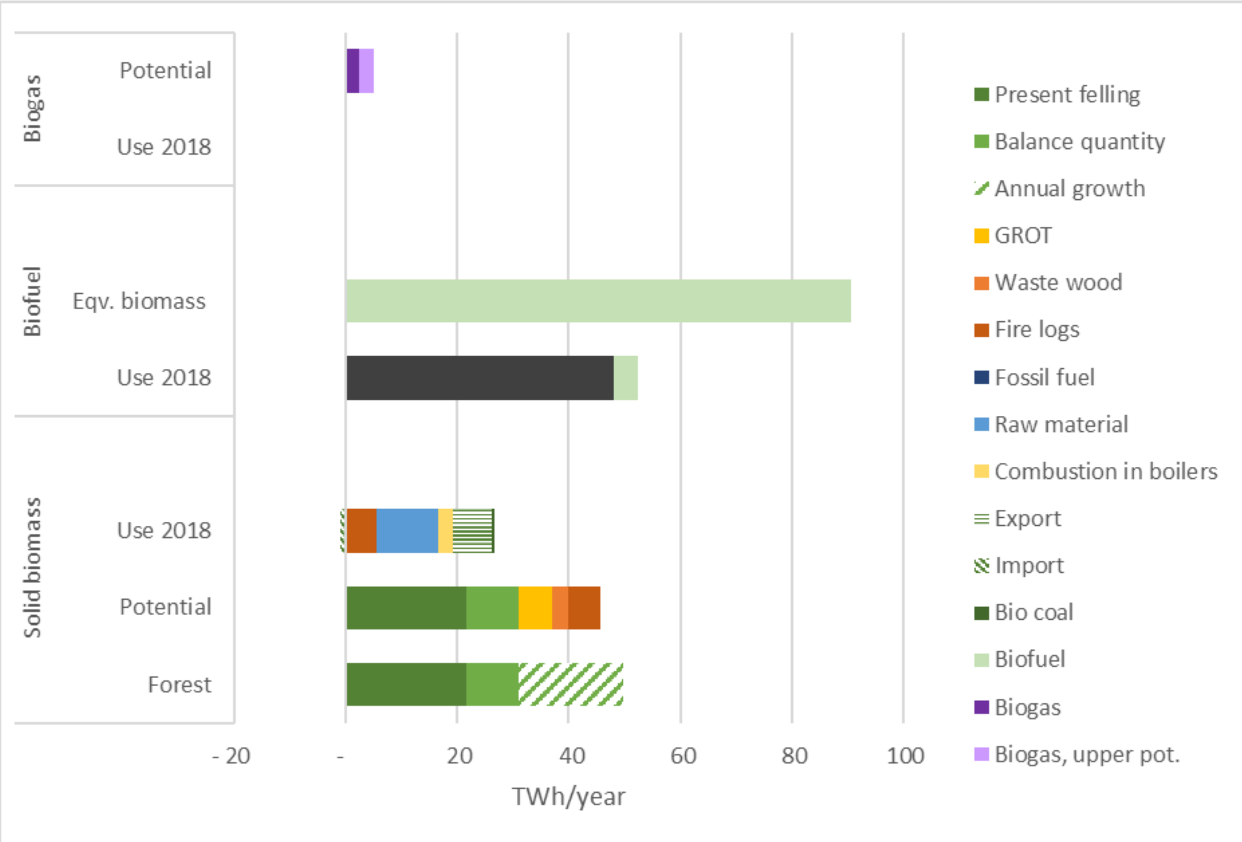


Figure 20 Biomass potentials and use, TWh/year

In the Base_Assumptions file, limitation of biomass is included. The limit is 15.7 TWh in 2018-2020, increasing to 31 TWh from 2030, according to the quantity of sustainable felling. A limitation of biogas is also added, 0.4 TWh in 2018-2020 increasing to 2.7 TWh in 2030. The production process of biogas is not included in the model yet.

Limitations of use of imported biofuel and bio coal are also included in the Base_Assumptions file. From 2035, no import of biofuels is possible, and with linear increased limitations from 2025 to 2035. Bio coal can be imported unlimited until 2035, and after 2035 it must be produced from Norwegian biomass resources.

The use of municipal waste is limited per region in line with the consumption of today. It is assumed to be constant at this level during the modelling horizon, due to lack of data. Increased population can argue for increased volumes of waste, but more recycling will reduce the waste available for energy purposes.

4.4 Hydrogen

Hydrogen can be produced and used in many different manners and many of them are still only in (early) developing stage. In IFE-TIMES-Norway, the technologies which are considered relevant for Norway are included and illustrated in Figure 21. The hydrogen can either be produced centralized or decentralized. The commodity H2-CENT is assumed to be low pressure hydrogen available directly after production (electrolyzer) and can be used in industry processes and for ammonia production. For storage and usage in transport segment (H2-TRA) it needs to be compressed into the commodity H2-COMP, which is assumed a compression level of 250 bar. The hydrogen is in addition both distributed and handled by filling infrastructure, which might increase the pressure further. In the figure, green boxes represent the source of which hydrogen is produced by, while yellow boxes represent the process of production, compression, and transport. Shaded boxes are processes that are currently not represented in TIMES, but in progress (liquification, refuelling station maritime), as well as simplified processes (ammonia and hydrogen for maritime). Blue hydrogen can be produced from steam methane reforming with CCS.

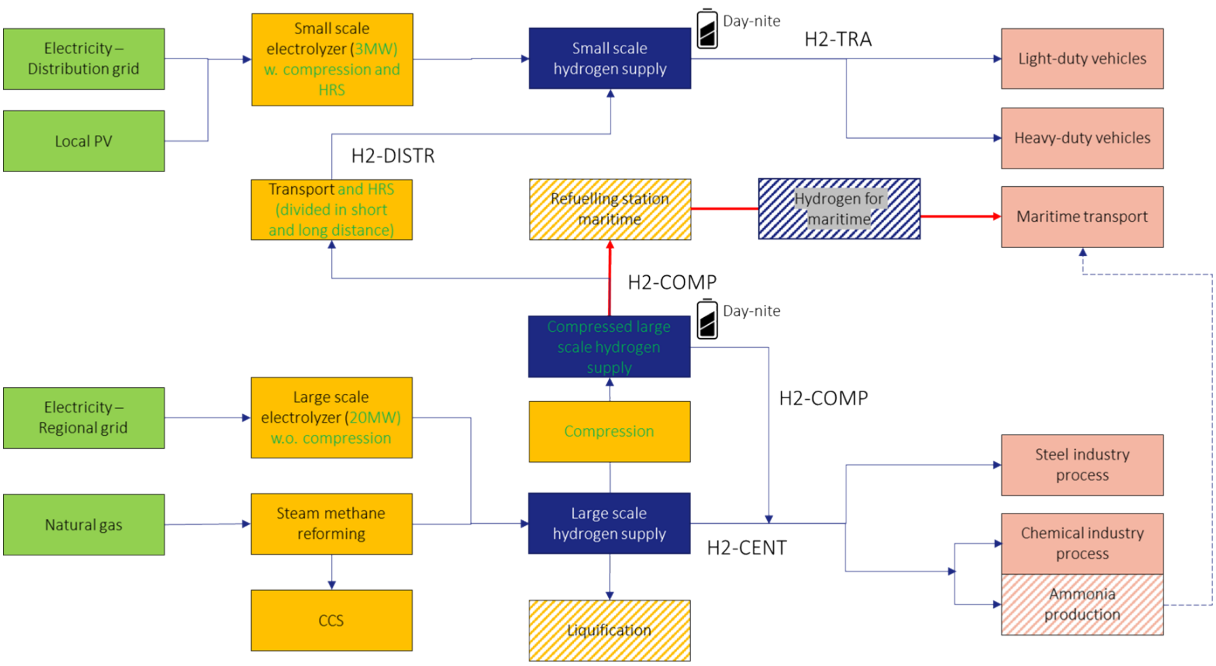


Figure 21 RES of hydrogen system presented in IFE-TIMES-Norway.

4.4.1 With electrolyser

Hydrogen from electrolyser is assumed to be produced in each region either large scale (centralized) or small scale (distributed) and cost wise are represented by a 20 MW_{el} and 3 MW_{el} installed capacity, respectively. The costs are provided both for alkaline and PEM electrolyser and are build up from three parts: electrolyser, compressor skid and other costs. The other costs cover engineering, control systems, interconnection, commissioning, and start-up costs. Aggregated investment costs are shown in Table 30, while used efficiency and lifetime of the electrolysers are presented in Table 31. The lifetime for electrolysers is usually presented in operational hours and its end of lifetime is based on when its efficiency drops below a set threshold due to the degradation of the fuel cell. In IFE-TIMES-Norway, a fixed lifetime in years is based on the plant's capacity factor of 95%.

A distinction between PEM and Alkaline electrolyser is made by allowing hourly (Daynite) variation in operation of PEM electrolyser, while Alkaline is allowed to vary between seasons.

The yearly OPEX costs incorporate the cost related both to the electrolyser type and the separate compressor and is shown in Table 30. The noticeable difference between large- and small-scale electrolyser is because small scale electrolyser includes a compressor to provide high pressure hydrogen to the commodity H2-TRA.

The large-scale and distributed electrolysers are in addition to CAPEX and OPEX distinguished by electricity source; where large-scale electrolyser is assumed to consume power from the high-voltage grid and the distributed electrolysers are dependent on the low-voltage distribution grid for which a grid tariff is included on top of the electricity cost.

In Appendix A, a more detailed explanation is made of how costs and technical values has been selected for the electrolysers and references to publications used in the selection process.

Table 30 Investment costs and OPEX for the different electrolysers

		Investment costs (NOK/kWel)			OPEX (NOK/kWH2)		
		2018	2030	2050	2018	2030	2050
20 MW el	PEM	17 400	11 400	5 400	383	251	120
	Alkaline	11 700	7 500	4 900	257	165	108
3 MW el	PEM	31 800	18 100	10 200	900	476	290
	Alkaline	34 700	18 800	13 400	1115	572	419

Table 31 Efficiency of large electrolyser and compression stage

	Alkaline			PEM		
Efficiency (%)	67%	68%	75%	58%	66%	71%
Lifetime (h)	79 000	100 000	132 000	63 000	79 000	132 000

4.4.2 With steam reforming of natural gas (SMR)

Production of hydrogen from steam reforming of natural gas (SMR) is allowed in NO2, NO3, NO4 and NO5, as these are the regions with available gas infrastructure. Natural gas is used as the input commodity, with an efficiency of 69%. Consequently 1.45 unit of natural gas is needed to produce 1 unit of blue hydrogen. As SMR is a proven technology, efficiency improvements are assumed to be marginal and is therefore kept constant towards 2050. The input parameters for producing hydrogen through SMR with CCS is based on IEA Global Hydrogen Review from 2021 [54]. The total annual OPEX is assumed to be 4% of total plant cost, while a 95% capture rate is used. Moreover, a 25-year lifetime and a 95% availability factors is used for hydrogen production from natural gas [54]. The group is currently updating the model, substituting "SMR with CCS" with "ATR with CCS" due to superior characteristics both in CO2 capture rate and costs. This will be updated in the next documentation report.

The total costs and technology parameters are summarized in Table 32.

Table 32 Cost and technology parameters of SMR with CCS.

	2018	2030	2050
Total plant cost (TPC) [kNOK/GWh]	12 941	12 941	12 941
Annual OPEX [% of TPC]	4%	4%	4%
Efficiency [%]	69%	69%	69%
Lifetime [years]	25	25	25
Availability factor [%]	95%	95%	95%
CO_2 capture rate [%]	95%	95%	95%

4.4.3 Storage

The storage of hydrogen is assumed to be at 250 bars. Cost for such storage is taken from [55] and is 6300 NOK/kg.

Storage within a day is available both for centralized and compressed hydrogen commodity (H2-COMP) and for local hydrogen production for transport (H2-TRA). Seasonal storage is only enabled in connection with centralized compression units.

4.4.4 Hydrogen refuelling station (HRS)

Necessary infrastructure for filling hydrogen provides a cost in addition to hydrogen production and in certain studies it accounts for about half the total hydrogen cost for the customer. Costs for HRS can vary greatly depending on size, pressure, degree of utilization and design. An overview from some sources is shown in Table 33. In [56], the cheapest 700 bar solution costed almost 40 NOK / kgH2 and the most expensive 350 bar solution costs slightly above 35 NOK / kgH2. At the same time as [57] shows that a large scale (1000 kg / day) 700 bar HRS can be as low as 32 NOK / kgH2, while if either HRS is smaller or has a lower utilization rate, costs increase. Based on available literature, an average cost of 40 NOK / kgH2 is assumed for the start year.

Table 33 Cost for HRS from different sources

		Light-duty vehicles	Heavy-duty vehicles	
		[56]	[58]	[57]
Pressure (bar)		700	350	350 & 700
Currency		USD_{2017}	USD_{2017}	NOK_{2018}
Cost per kg_{H2}	Max	7	5.5	66
	Min	3.8	1	32

In addition, a reduction in cost is expected over time. In [56], the cost reduction is connected to the increase of HRS increases globally. An increase from 375 HRS in operation 2018 globally to approximately 5 000 and 10 000 stations, the costs may decrease by 40% and 45% respectively. In IFE-

TIMES-Norway, it is assumed that by 2030 there will exist 5 000 HRS stations globally and in 2040 there will be 10 000 HRS stations globally.

4.4.5 Hydrogen transport and trading

Hydrogen can in theory be transported both long and short distances. In practice, cost-effective long-distance transport of hydrogen is a relatively immature technology that is expensive and requires large-scale demand volume to motivate building of hydrogen pipelines or alternative transport solutions for liquified hydrogen. The latter has notable cost and energy efficiency penalties.

Therefore, trade in hydrogen has only been added for adjacent geographical areas within Norway and the costs for it are based on the distance between the main cities within each region. The distance between regions and costs of transport are shown in Table 34. The cost calculations are based on transport of hydrogen in a 40-foot tube trailer by truck and a total daily delivery of 2000 kg hydrogen transported in several tube trailers.

Table 34 Distance between regions and transport costs used in trading of hydrogen

From		To		Distance (km)	Transport costs (NOK/kg_{H2})
NO1	Oslo	NO2	Kristiansand	320	15
NO1	Oslo	NO3	Trondheim	490	23
NO1	Oslo	NO5	Bergen	460	22
NO2	Kristiansand	NO1	Oslo	320	15
NO2	Kristiansand	NO5	Bergen	470	22
NO3	Trondheim	NO1	Oslo	490	23
NO3	Trondheim	NO4	Tromsø	1100	49
NO3	Trondheim	NO5	Bergen	700	32
NO4	Tromsø	NO3	Trondheim	1100	49
NO5	Bergen	NO1	Oslo	320	15
NO5	Bergen	NO2	Kristiansand	470	22
NO5	Bergen	NO3	Trondheim	700	32

The hydrogen used in the transport sector can either be produced centralised and distributed or be produced locally, as illustrated in Figure 22. The costs of distributing hydrogen within a region will depend on the geographical size of the region. The distance and connected costs of distribution are developed using a simple method based on the distance between regions showed in Table 34. As a first step, a distance (D) is calculated as the average between a region of interest and all adjacent regions. The main cities in each region are assumed to be roughly in the centre of the region and that the D can be simplified as distance between centre points between two circular regions, as shown in Figure 22. In the second step, it is assumed that the regions have approximately the same size and that initial large-scale production of hydrogen will be close to the main city of each region. A part of hydrogen demand for road transport will be relatively close to the production site and defined as an average distance of D/6 (short distance), while other part of demand will be on average distance of D/3 (long distance), as shown in Figure 22. The average distance between regions, the short and long distance of distribution and costs for distribution in IFE-TIMES-Norway is presented in Table 35 and are based on a 40-foot tube trailer that distributes 500 kg per day.

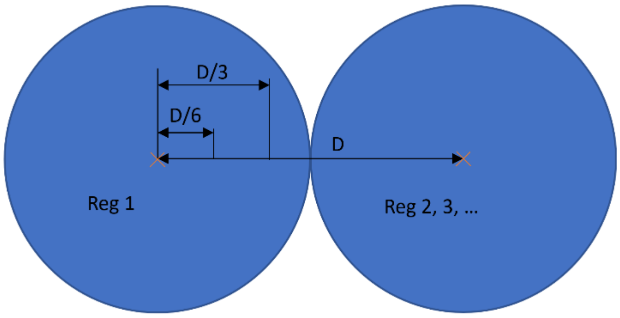


Figure 22 Illustration of how distance of distribution within regions are developed.

Table 35 Values used to calculate distribution costs with each region and the distribution costs itself.

Region		Average distance to other regions, D (km)	Long transport within region		Short transport within region	
			D/3	NOK/kg	D/6	NOK/kg
NO1	Oslo	423	141	9	71	6
NO2	Kristiansand	395	132	9	66	6
NO3	Trondheim	763	254	14	127	9
NO4	Tromsø	1100	367	19	183	11
NO5	Bergen	497	166	10	83	7

As the hydrogen demand will increase over time, it is assumed that several large-scale production sites will be available in each region and by that the distance of distribution reduced. This development is modelled by assuming that in 2030 only 50% of hydrogen for transport can be supplied through short distance distribution, while the share increases to 100% by 2050. This variable is set exogenous, but is strongly dependent on the model results, which makes it a central parameter for sensitivity analysis of the hydrogen supply chain for the transport sector. The distribution costs of hydrogen are defined in such a detailed matter to be able to analyze the role of locally produced hydrogen.

5 End-use demand

5.1 Industry

5.1.1 Structure and demand projection

The industry sector is divided in the following sub-sectors:

- ALU - Aluminium industry
- METAL - Metal industry (production of other raw metals)
- CHEM - Chemical industry
- WOOD/Tre - Wood industry (production of pulp & paper, sawmills)
- MIN - Mineral industry
- Light - Light industry (food, metal products…..)
- Petro - Petroleum industry (power from onshore to offshore activities and onshore petro plants)
- NEW – Battery factories, data centres
- AGR&CON - Agriculture and construction
- Export-H2 – export of blue hydrogen

Each sub-sector has a demand of heat, electricity (for non-heating purposes) and raw materials. The demand is defined by the energy balance of 2018, see Figure 23.

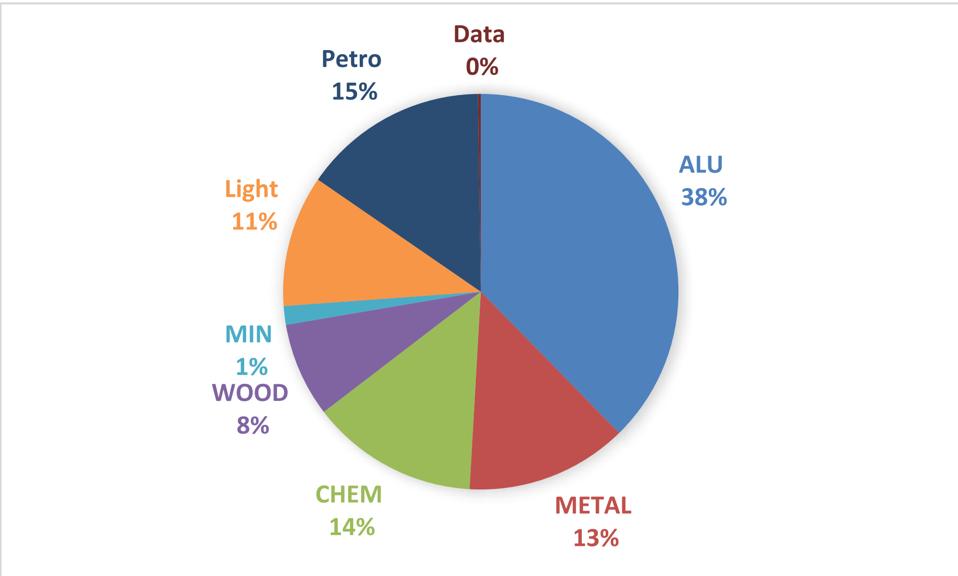


Figure 23 Share of electricity for non-heating purposes by sub-sector of total use in industry in 2018, TWh/year

The demand projection is often scenario/project specific and in the base version of the model a projection in line with today's expectations is included, see Figure 24 and Figure 25. In this base assumption, the following is included:

- Aluminium: One new production line
- Other metal production: two more production lines
- Chemical industry: four more production lines
- New activities: battery factories and datacentres with a total electricity use of 20 TWh in 2050

- Petroleum: No oil refineries in 2050 and 1/3 of the oil & gas extraction of today (based on Perspektivmeldingen 2021 [59])
- Mineral: constant at today's level
- Light industry: constant at today's level
- Agriculture: constant at today's level
- Construction: constant at today's level

The division between other metal production and chemical industry follow the principles of the energy balance. Hydrogen plants for use as fuel in transportation, is modelled as necessary supply to transportation demand (endogenous), rather than exogenous industry demand. In the total demand, use of raw material with CO2-emissions is also included, in order to calibrate the model with actual CO2 emissions.

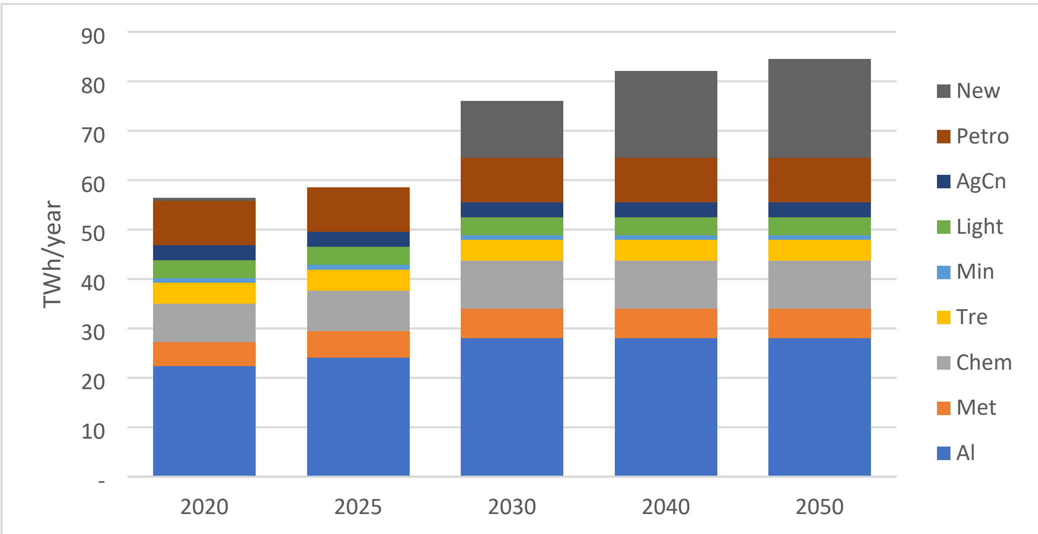


Figure 24 Electricity specific demand in base scenario of industry, from 2020 to2050, TWh/year

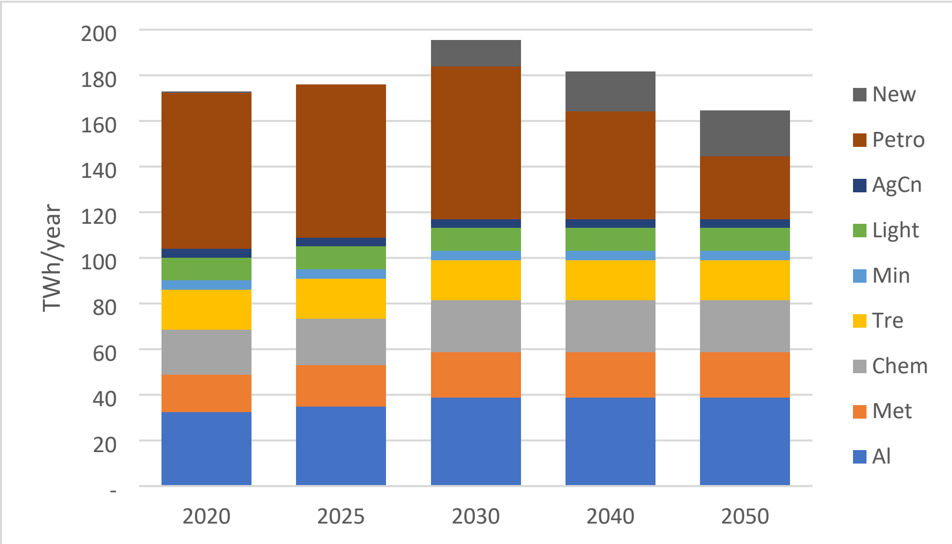


Figure 25 Total energy service demand (heat, electricity specific, raw material) in industry from 2020 to 2050, TWh/year

The load profile of all industry sub-sectors, besides light industry, is assumed to be flat, i.e., continuous operating time during the entire year. In light industry, a daily load profile is used, see Figure 26, assuming no seasonal variation. The profile is equal to that of commercial buildings [60, 61].

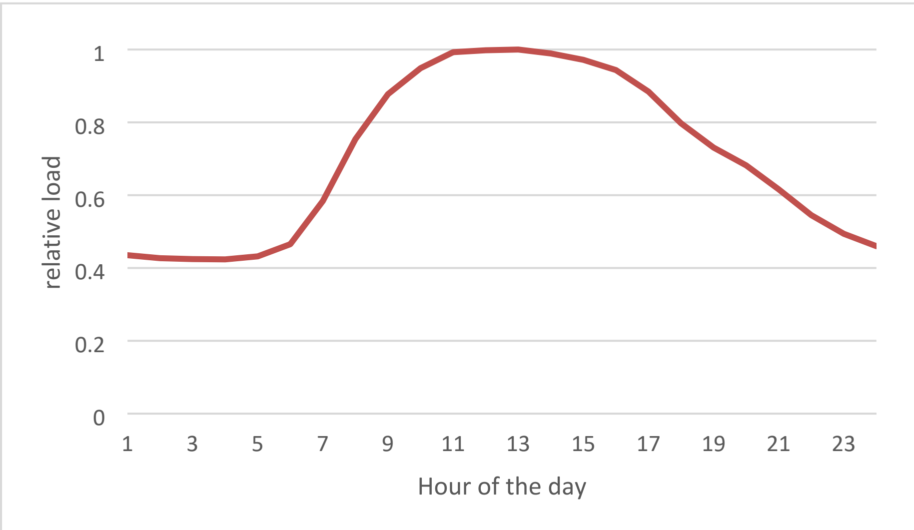


Figure 26 Daily load profile in light industry

5.1.2 Demand technologies

The electricity use for non-heating purposes is modelled as one technology using ELC-HV in industry sub-sectors. There are two exceptions, i) light industry using ELC-LV-L and ii) agriculture and construction using ELC-LV.

All industries can use fossil energy or electricity for heat production. Biomass can be used in wood, mineral and light industry. In addition, district heat and heat pumps can be used in light industry, with an upper limitation. The technology data (investment costs, efficiencies, life time) are based on [18]. Agriculture and construction are modelled with a share for different energy carriers. In 2018, the share is fixed in accordance with the energy balance and in 2040 an upper limit is applied.

In addition to CCS, other possibilities to reduce the CO2 emissions are included. One possibility is to substitute use of fossil coal by charcoal. This is possible in other metals, chemicals, and minerals. Since it is not possible to substitute all fossil coal by charcoal, a limit of maximum 30% in 2030 and 40% in 2040 is applied in other metal production and chemicals. In mineral industry, an upper limit of 25% is applied [62].

Use of coal as raw material in other metals and chemical industry has the possibility to be replaced by hydrogen, with an upper bound of use based on available literature (uncertain data). Use of electrolysis and hydrogen instead of natural gas is a possibility in chemical industry. For Yara, actual data is used. In addition, hydrogen usage in the chemical industry is assumed to increase by 50% from 2040. In other metal production, use of hydrogen at Tizir is added from 2025, with a possible increase from 2040 by another 125%. [62, 63]

Use of gas for electricity production in oil and gas extraction is included in the subsector Petroleum. The future consumption is based on Perspektivmeldingen 2021 where the activities in 2050 is about 1/3 of the activities in 2024 (falling from 256 mill. Sm3 o.e. in 2024 to about 83 mill. Sm3 o.e. in 2050) [59]. It is assumed that electricity from the grid can supply half of the demand from offshore activities in 2030 and all from 2040.

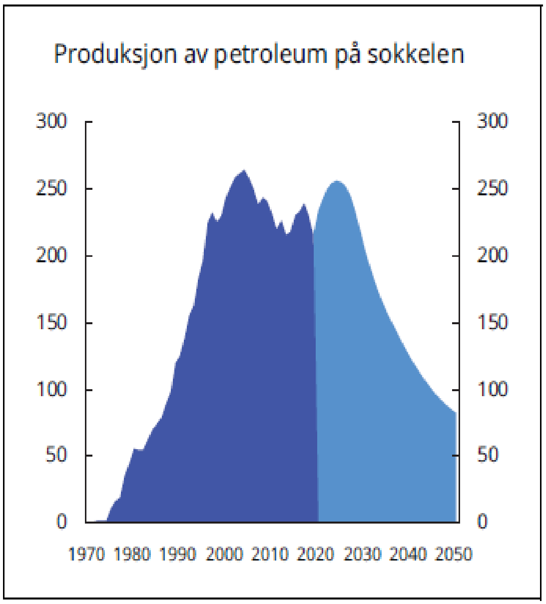


Figure 27 Production and projected production of petroleum on Norwegian shelf, mill. Sm3 o.e. [59]

5.1.3 CCS

CCS in cement production and metal production is included as a possibility in SubRES files: SubRES_CCS and SubRES_CCS_Trans, with region specific data in the Trans-file. Potentials are based on [63, 64]. These files also include CCS in waste incineration in district heating plants and in production of blue hydrogen (see 4.4.2).

The technology data for the CCS processes are based on data from Miljødirektoratet [64]. Electricity consumption is estimated to 0.45 TWh/Mt CO2 and heat consumption to 0.85 TWh/Mt CO2. The capture rates are presented in Table 36.

Table 36 Capture rates and investment costs for CCS for different plants

	Capture rates			Investment costs (NOK/ton CO2)	
Year:	**2025**	**2030**	**2035**	**2020**	**2035**
Cement production	0.47	0.47	0.90	2500	1000
Metal production	0.70	0.70	0.80	3750	1500
Waste incineration	0.67	0.76	0.76	2500	1000
Other / Blue hydrogen	0.95	0.95	0.95	2500	1000

5.2 Buildings

5.2.1 Structure

The building sector of TIMES-Norway is divided in residential single-family and multi-family houses and in non-residential/commercial buildings for each of the model regions. All buildings are divided in existing and new buildings. The existing buildings have a stock of equipment in the start year. The end-use demand is divided in central heating (HC), point source heating (H), hot water (W) and electricity specific demand (E).

A schematic overview of the systems in residential and commercial buildings is presented in Figure 28 and Figure 29. Oil boiler is only available before 2020. Solar collectors are added as a possible technology with start year 2100. Demand for hot water is added to demand for space heating in buildings with central heating, while for buildings with point source heating it is modelled as a separate demand.

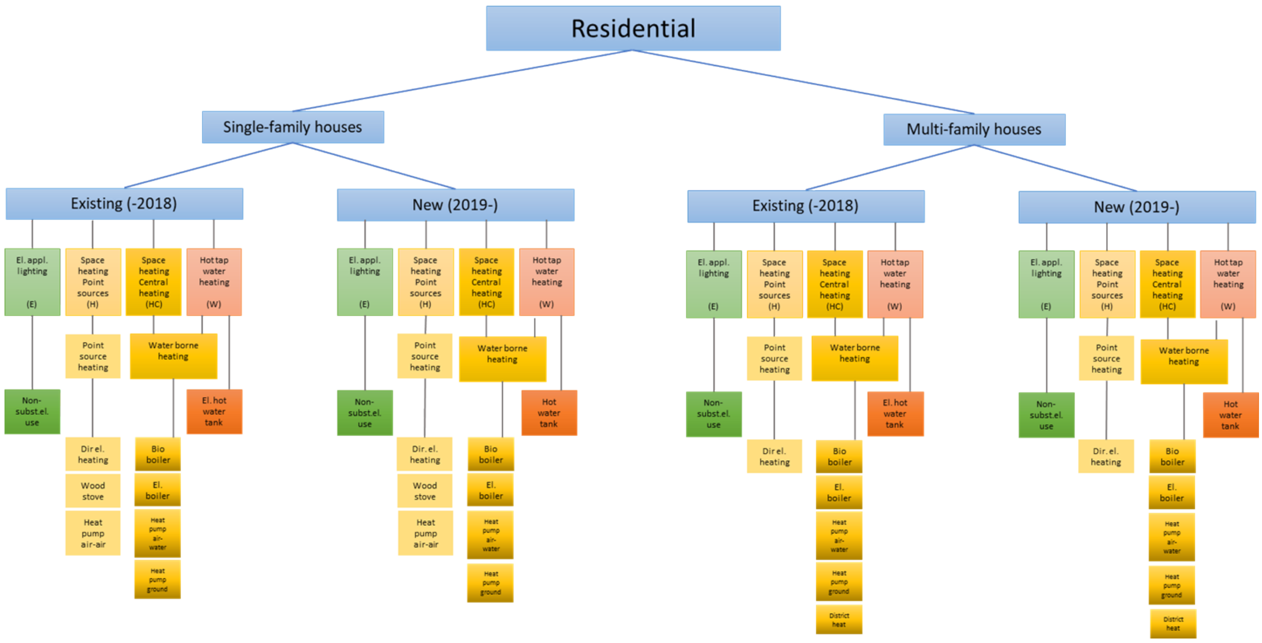


Figure 28 Schematic overview of the energy system in residential sector

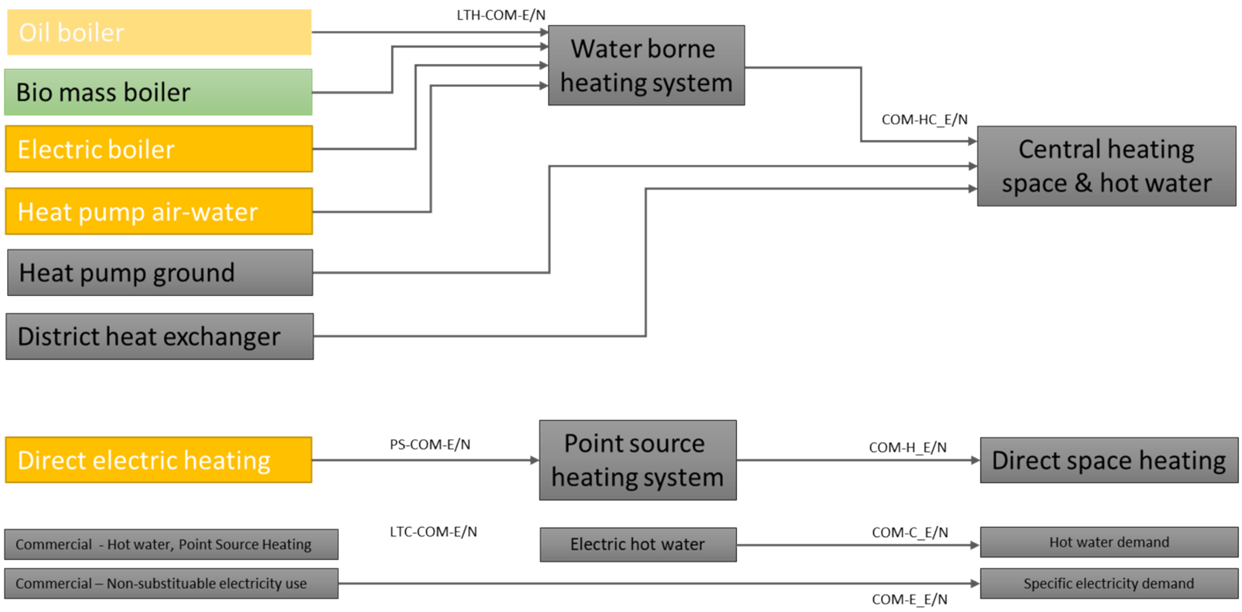


Figure 29 Schematic overview of the energy system in commercial buildings

Heating is divided in central heating (water borne system) and "point source" heating based on data from the FlexBuild project [65]. The assumptions regarding the share of point source and central heating in the building sectors are presented in Table 37.

Table 37 Share of point source and central heating in the building sectors

	Point sources	Central heating
Multi-family houses, existing	62 %	38 %
Multi-family houses, new	12 %	88 %
Single-family houses, existing	88 %	12 %
Single-family houses, new	88 %	12 %
Commercial buildings, existing	37 %	63 %
Commercial buildings, new	10 %	90 %

District heating and ground source heat pumps are connected directly to heating demand in order to get the same profile as the demand (if a building has district heat it cannot have any other heating source when modelled as this). Biomass boilers are modelled on a seasonal level, since they normally are more difficult to operate on an hourly level with rapid on/off.

5.2.2 Demand projections and load profiles

The demand projections in residential and non-residential buildings are based on data from previous work in the FlexBuild project [65], see Figure 30. It is based on the scenario "Energy Nation".

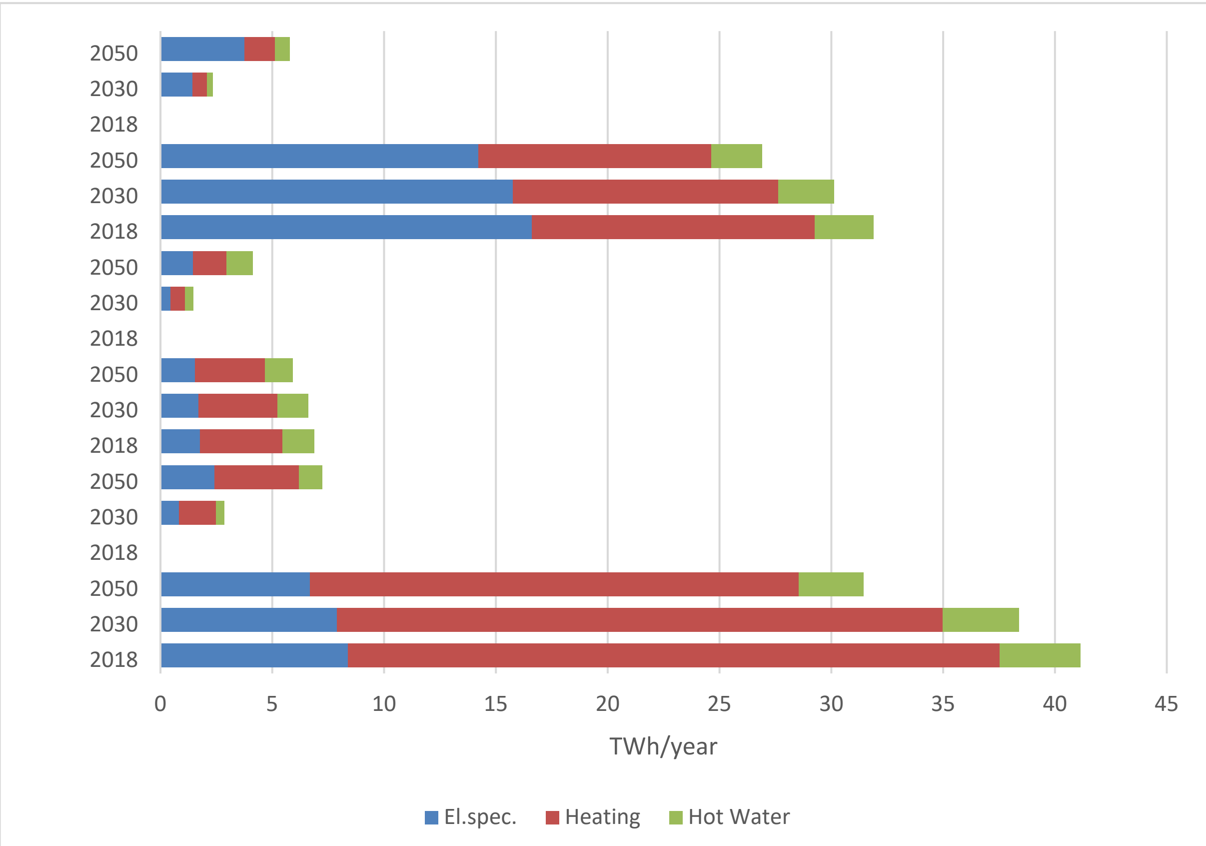


Figure 30 Projections of energy service demand in residential and commercial buildings, 2018, 2030 and 2050, TWh/year

The load profiles, the sub-annual hourly load variations, are based on input from [60, 61]. In the base model, we assume that the load profiles are the same for all years and for existing and new buildings. The heating profiles differs between regions and for central heating/ point source heating. The profile for non-substitutional electricity is the same for all residential buildings and all non-residential buildings. Examples of load profiles in region NO1 is presented in Figure 31, Figure 32 and Figure 33.

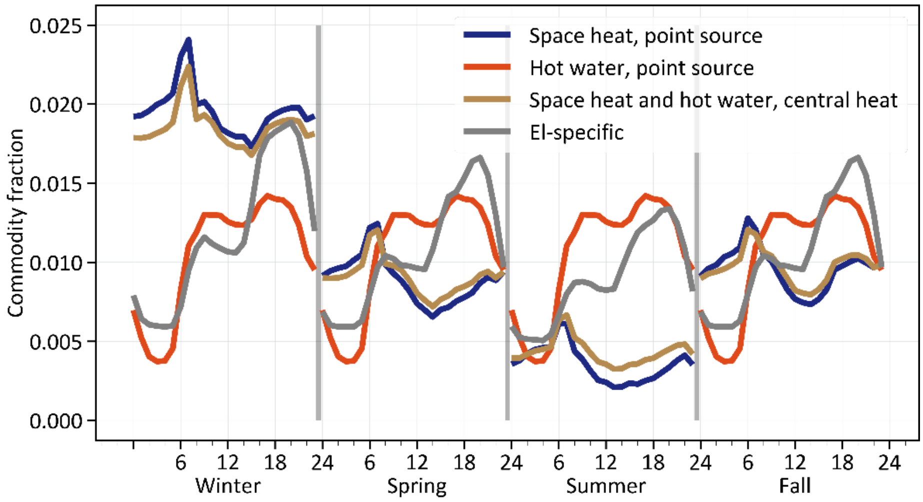


Figure 31 Load profile for residential single-family house in model region NO1.

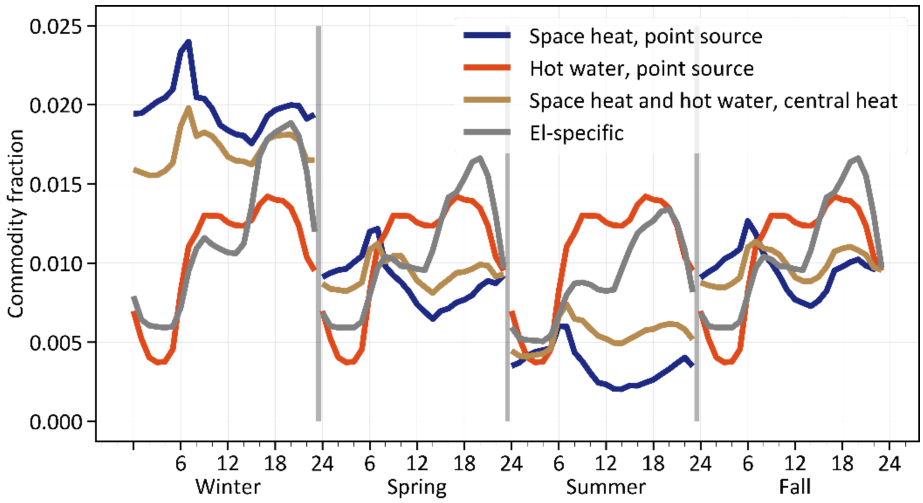


Figure 32 Load profile for residential multifamily house in model region NO1.

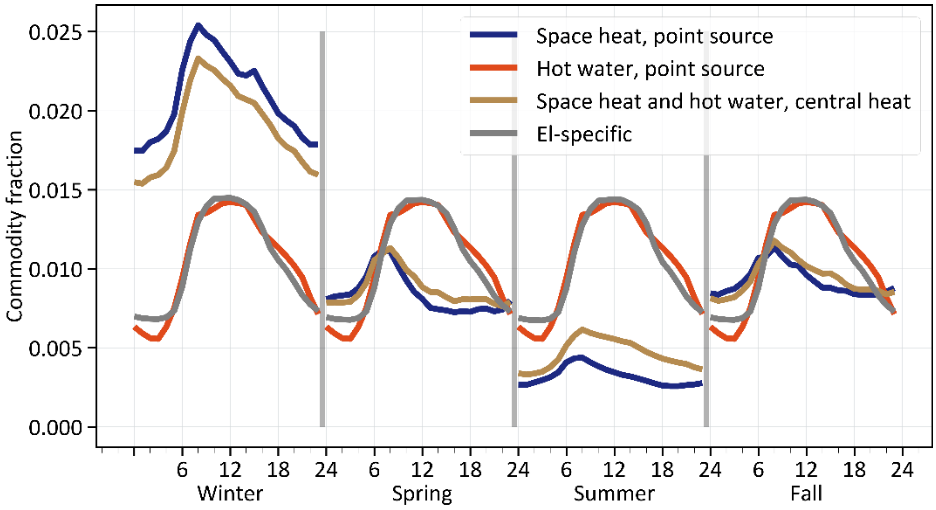


Figure 33 Load profile for commercial buildings in model region NO1.

5.2.3 Demand technologies

5.2.3.1 Heating equipment

The investment and operational costs, annual full load hours, efficiencies, life times and technology learning rates are based on [18] and presented in Table 38. Equipment in the residential sector includes 25% VAT.

Existing oil boilers have 2 years lifetime, and it cannot be invested in new oil boilers, and oil boilers can consequently not be used from 2020. Stock of existing heating equipment is calculated based on energy use in 2018 and full load hours from [18].

The efficiency and the availability of heat output of air-air heat pumps and air-water heat pumps depends on the outdoor temperature [66] and is therefore modelled on DayNite level for each of the five regions, see Figure 34. The nominal COP_{33N} for air-water and COP_{13N} for air-air is an average of rated COP's of commercially available heat pumps in each category.

Table 38 Technology data of heating equipment in buildings

Description	Efficiency /COP	Market Share	LIFE	INVCOST	INVCOST 2035	FIXOM	VAROM
			years	NOK/ kW	NOK/kW	NOK/ kW	NOK/ MWh
Residential Multi-family							
Central heating							
Biomass boiler	0.81		15	7 897	7 739	919	8 96
Electric boiler	0.98		20	1 546	1 546	540	1 35
Solar collector	1.00	0.10	25	5 714	4 000	38	
District heat exchanger	0.99		50	482	482	-	-
Heat pump water-water	3.0	0.56	20	15 643	12 514	40	15
Heat pump air-water		0.39	15	6 790	5 432	40	15
Point sources							
Heat pump air-air		0.27	15	6 872	5 498	30	
Wood stove	0.4		25	3 002	3 002	45	
Direct electric heating	1.00		25	2 042	2 042	31	12 5
Electric water heater	0.98		20	2 371	2 371		
Residential Single-family							
Central heating							
Biomass boiler	0.81		15	12 876	12 618	919	8 96
Electric boiler	0.98		20	4 046	4 046	540	1 35
Solar collector	1.00	0.10	25	10 715	7 501	38	
Heat pump water-water	3.0	0.28	20	20 523	16 419	40	15
Heat pump air-water		0.36	15	17 966	14 373	40	15
Point sources							
Heat pump air-air		0.27	15	6 872	5 498	30	
Wood stove	0.4	0.5	25	3 002	3 002	45	
Direct electric heating	1.00		25	2 042	2 042	31	12.5
Electric water heater	0.98		20	2 964	2 964		
Commercial							
Central heating							
Biomass boiler	0.84		15	7 897	7 739	510	7.3
Electric boiler	0.98		20	1 546	1 546	32	1
Solar collector	1.00	0.05	25	5 714	4 000	20	
District heat exchanger	0.99		50	918	918		
Heat pump water-water	3.0	0.3	20	15 643	12 514	32	12
Heat pump air-water		0.4	15	6 790	5 432	32	12
Point sources							
Direct electric heating	1.00		25	1 226	981	15	8
Electric water heater	4.00		25	2 371	2 371	60	60

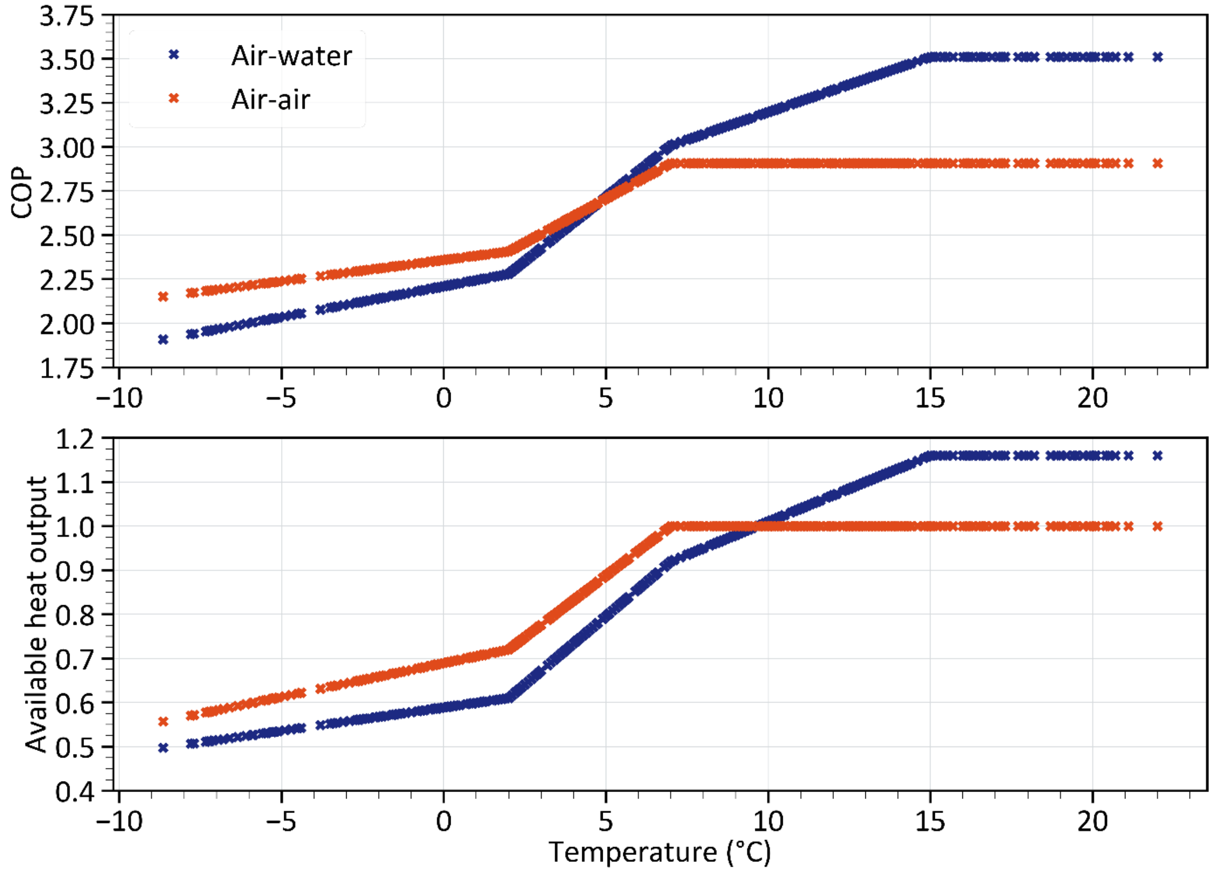


Figure 34 Temperature dependent COP and heat output of nominal capacity for air-water and air-air heat pumps.

A maximum market share is added for heat pumps (see Table 39) and district heating, see 4.2.3. NVE has estimated coverage and prevalence for three types of heat pumps in three types of buildings, see Table 39.

Table 39 Market share of heat pumps

	Heat pump type	Air-to-air	Air-to-water	Water-to-water
Coverage	Old buildings	40 %	65 %	80 %
	New buildings	50 %	75 %	90 %
Prevalence	Single-family houses	90 %	90 %	21 %
	Multi-family houses	0 %	60 %	70 %
	Commercial	0 %	80 %	70 %
Max market share	Existing dwellings	27 %	54 %	26 %
	New dwellings	34 %	62 %	30 %
	Existing commercial	-	52 %	56 %
	New commercial	-	60 %	63 %

Wood stoves can only be used in winter hours 16-24, fall and spring hours 18-22, in order to reflect actual use of wood firing, see Figure 35. The efficiency of wood stoves is lower than actual, to reflect that not all produced heat is useful (some is used for extra comfort, part of the time the temperature is above the needed comfort temperature etc.). Wood stoves can only cover 50 % of heat demand.

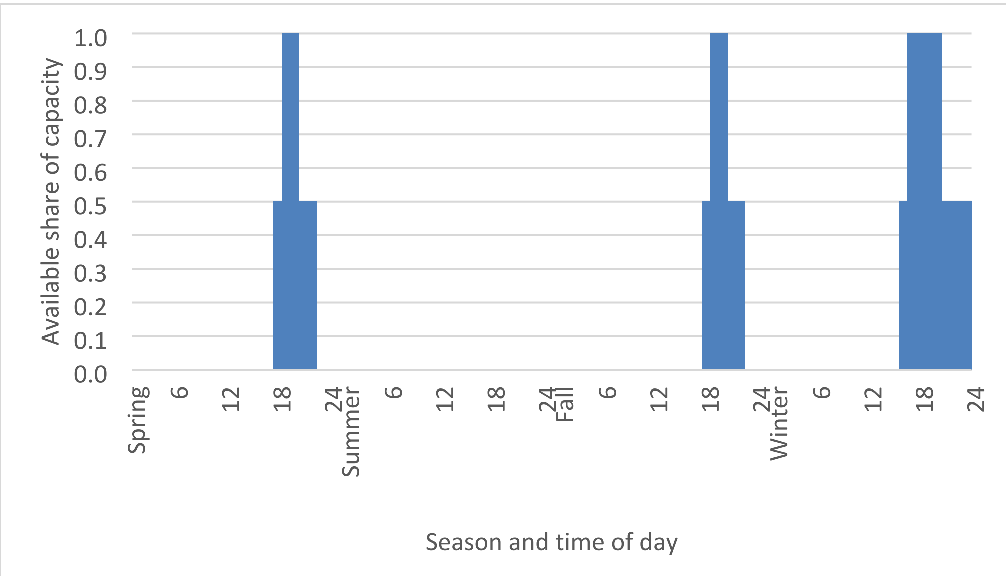


Figure 35 Illustration of available share of capacity for wood stoves per season and time of day (hour).

5.2.4 Flexible hot water tanks

Flexible hot water tanks are included in the model as a Scenario file, which means that it needs to be activated in runs where such flexibility is desired (start year 2100 in base and 2022 in Scen_Flex-VVB). The storage tanks are modelled with a flexible and a non-flexible share. The non-flexible part needs to deliver at least 70% of the total hot water demand, both for new and existing buildings. This is an uncertain share, based both on minimum demand of temperature level of the tank (due to avoiding legionella problems) and work done by [67]. This is modelled as a normal electric water heater, with low-voltage electricity as input and hot water as output commodity. The investment cost corresponds to the average cost of several existing hot water tanks in the market. The flexible part of the storage tank can deliver up to 30% of the demand and is modelled using the same approach as for battery storage. The relationship between power output and energy content, the c-rate, is set to 0.28, also defined by existing storage tanks. The additional cost of installing a flexible hot water tank compared to a conventional one is around 3000-5000 NOK [68]. As model input, an average cost of 4000 NOK is assumed for an average capacity of 13 kWh. Information regarding technical parameters and investment costs for the conventional hot water tank and the flexible part is presented in Table 40. In IFE-TIMES-Norway, flexible hot water tanks can only be installed in new tanks, meaning that existing water heaters cannot be retrofitted to be flexible.

Table 40 Parameters and costs for non-flexible and flexible part of hot-water tank (without VAT).

	Investment cost	Efficiency	Storage loss	c-rate	Share of demand
Hot water tank – non-flexible	2 371 NOK/MW	98%			70% (min)
Hot water tank – flexible	103 NOK/kWh	98%	3.3%	0.28	30% (max)

5.3 Road Transport

5.3.1 Structure

The road transport is divided into six different types and are listed in Table 41 together with a short description.

IFE

Table 41 Description of the different road transport demand types

Type	Name in TIMES	Description
Cars	TCAR	Vehicles transporting up to 9 persons including driver. Taxis, and ambulances are also included in this group.
Vans	TVAN	Vehicles designed for carriage of goods with gross vehicle weight below 3.5 ton. It corresponds the Norwegian Public Roads Administrations vehicle group N1. In addition are included motorhomes and combined cars (an outdated government definition of vehicles designed for both person and goods transport).
Trucks	TTRUCK-S	Trucks with registered total gross weight including trailer between 3.5 and 50 ton, all distances (S as in Small)
	TTRUCK-LS	Trucks with registered total gross weight including trailer above 50 ton and for short haulage (<300km) (LS as in Large and Short)
	TTRUCK-LL	Trucks with registered total gross weight including trailer above 50 ton and for long haulage (>300km) (LL as in Large and Long)
Bus	TBUS	Vehicles transporting 10 persons or more.

The demand for heavy-duty trucks is divided in three segments as its size and daily milage is central parameters for energy consumption and feasibility for different propulsion systems. They will also have different demand for fast charging, if electrified. In Table 42, the classification of the three segments by daily truck mileages is given. The color-coding follows the milage distribution given in Table 41, and is as follow: yellow for TTRUCK-S, red for TTRUCK-LS ad purple for TTRUCK-LL. Engine size above 500 hp is typically used in tractor units with semi-trailer, but also for trucks who provides more demanding services. It can for example be a road-train set-up with max 24 m length and total gross weight of 60-ton, mass transport to/from construction sites or other special purpose vehicles.

Table 42 Distribution of trucks daily mileage for vehicles 5-year-old and newer [69].

Engine power (HP)	Up to 100 km	100-200 km	200-300 km	300-400 km	400-500 km	500 km and over	Total
100-199	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.2%
200-299	2.5%	2.2%	1.1%	0.6%	0.2%	0.2%	6.8%
300-399	2.8%	2.8%	1.1%	0.7%	0.2%	0.2%	7.8%
400-499	4.7%	4.4%	2.9%	1.0%	0.6%	2.2%	15.8%
500-599	12.4%	8.3%	6.6%	4.1%	5.3%	17.6%	54.3%
600-699	2.1%	1.1%	0.9%	0.6%	0.8%	2.7%	8.2%
700+	2.0%	0.9%	0.7%	0.5%	0.7%	2.4%	7.2%
Total	26.6%	19.8%	13.2%	7.5%	7.6%	25.3%	100.0%

The transport demand overview, its forecast and fleet composition for Norway is prepared by the Norwegian Institute of Transport Economics (TØI) through their Freight Transport model (GTM based on its Norwegian Acronym) and stock-flow cohort model of the Norwegian vehicle fleet (BIG based on its Norwegian Acronym). It is essential to easily transfer data from TØI's forecasts, especially BIG model as it provides the decomposition of the heavy-duty transport fleet into trucks and tractor units, as well as into different sizes. The vehicle sizes are divided in BIG based on registered total gross weight including trailer and its decomposition for year 2018 is shown in Table 43.

Table 43 Million vehicle km distribution across vehicle registered total gross weight for different vehicle types for year 2018 based on data from BIG [70]

Registered total gross weight including trailer	Trucks	Tractor units	Total	Share of total
3.5-7.5 ton	38	0	38	2%
7.5-12 ton	97	0	97	4%
12-20 ton	130	2	132	6%
20-30 ton	105	13	118	5%
30-40 ton	49	10	59	3%
40-50 ton	113	14	127	5%
50-60 ton	147	41	188	8%
60 + ton	1066	478	1544	67%
Sum	**1743**	**558**	**2302**	**100%**

In IFE-TIMES-Norway, it is assumed that all vehicles with registered total gross weight including trailer above 50 ton corresponds to vehicles with engine size above 500 hp. The match is not perfect but provides a rational and simple linkage to BIG model. The vehicle km for vehicles above 50-ton gross weight is divided into two equal parts to represent short and long haulage. Information from TØI results in a trend with less smaller trucks and more heavy trucks, see Figure 36.

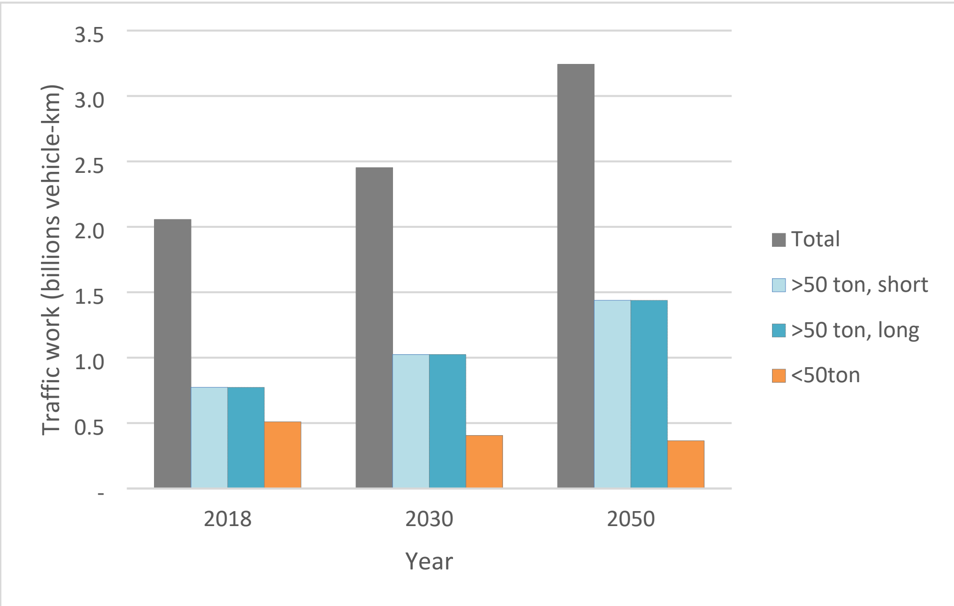


Figure 36 Development in demand for three types of trucks, 2018, 2030 and 2050 (bill. vehicle-km / year)

5.3.2 Demand

The demand towards 2050 is based upon the projections made in the national transport plan (NTP) 2022-2033 [71] and is shown in Figure 37. Only national data of demand for buses in passenger-km are available from NTP, and therefore data from TØIs BIG-model on vehicle-km is used for the base year. The division on regions is based on population per region. The projection is based on relative change in passenger-km from NTP.

The total heavy freight transport is based on data from NTP 2022-2033 and is divided in the three truck classes of IFE-TIMES-Norway as described in the previous paragraph. The division of data per region and the relative development from 2018 to 2050 is based on county data of NTP 2022-2033.

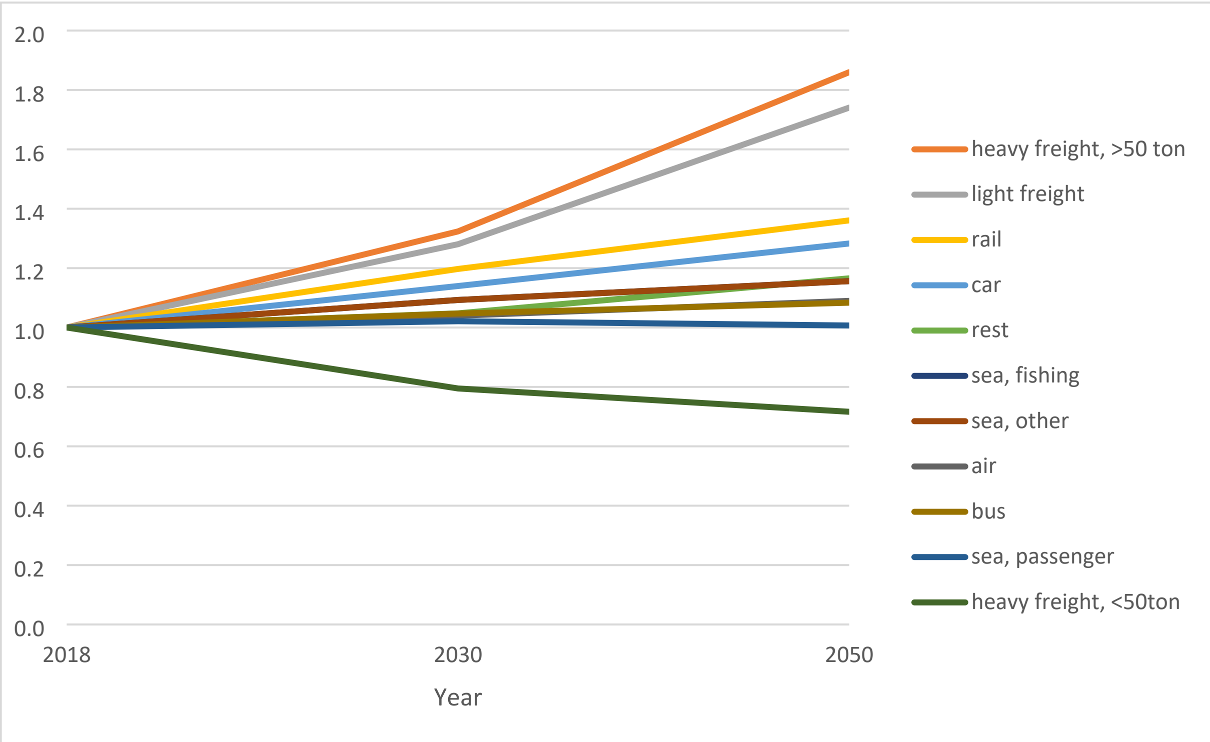


Figure 37 The relative change of demand for the default scenario (NTP) in 2018, 2030 and 2050

5.3.3 Available powertrains

In IFE-TIMES-Norway, various technologies or powertrains can be used to satisfy the transport demand. The powertrains included in IFE-TIMES-Norway are internal combustion engine (ICE), plug-in hybrid with ICE, battery electric, fuel cell electric and gas-powered ICE. A more detailed description of each powertrain is presented in Table 44.

IFE

Table 44 Description of powertrains, how they are defined in IFE-TIMES-Norway and input commodities.

Power trains	Description of powertrain	Powertrain definition in TIMES	Commodity used
ICE	Within this category is aggregated ICE using petrol and diesel. In addition, hybrid vehicles which are not plug-in are included here. They can use fossil fuel, biofuel or a mix	XXX-ICE	FOS BIO-FUEL
Plug-in hybrid	In similarity with ICE powertrain, both petrol and diesel engines are considered. In addition, a share of energy can be supplied by electricity.	XXX-PLUG	FOS BIO-FUEL ELC-LV
Battery	Battery electric vehicle are modelled to be charged by electricity provided from charging infrastructure	XXX-ELC	ELC-CAR
Fuel cell	Fuel cell and battery hybrid system entirely powered by hydrogen. Hydrogen production and handling is modelled separately in IFE-TIMES-Norway.	XXX-H2	H2
Gas powered ICE	Based on liquid or compressed biogas used in ICE for urban buses.	XXX-GAS	GAS

Various of the powertrains have several commodities as input and limitations on the share is defined for some of the commodities. An overview of the limitations is shown in Table 45. Biofuels represented 12% of volumetric fuel demand for road transport in 2018 [72], it is simplified in IFE-TIMES-Norway to also represent the energy demand covered by biofuels in the starting year. Norwegian law requires to reach at least 20% share of biofuels by 2020 including minimum 4% of advanced biofuels, which are allowed to be double counted in the legislation [73]. This implicates an actual blending with minimum 16% of biofuels in 2020 and it is fixed to this limit in the model. The upper limit is allowed to reach 100% by year 2040.

The share of electricity usage in plug-in vehicles depends on a wide range of parameters and is difficult to estimate. In IFE-TIMES-Norway, the data presented in [74] of 30% electricity share, based on measured data from www.spritmonitor.de, are used. As shown in Table 45, the value is assumed to be constant in IFE-TIMES-Norway until 2050.

Table 45 Share of commodities for certain powertrains.

		2018	2020	2040	2050
BIO-FUEL input for ICE	Max	12%	12%	19%	100%
	Min	12%	12%	19%	19%
Electricity input in plug-in hybrid	Max	30%	30%	30%	30%

When considering the specific conditions in the Norwegian transport sector and current technological development, not all the powertrains are considered of relevance for all the different demands. In

Figure 38, an overview of which powertrains are considered for each type of road transport demand is presented. Battery powertrain is defined for large trucks with long haulage but is usually not included in reference scenarios as per today it is uncertain whether such a solution would be technically feasible.

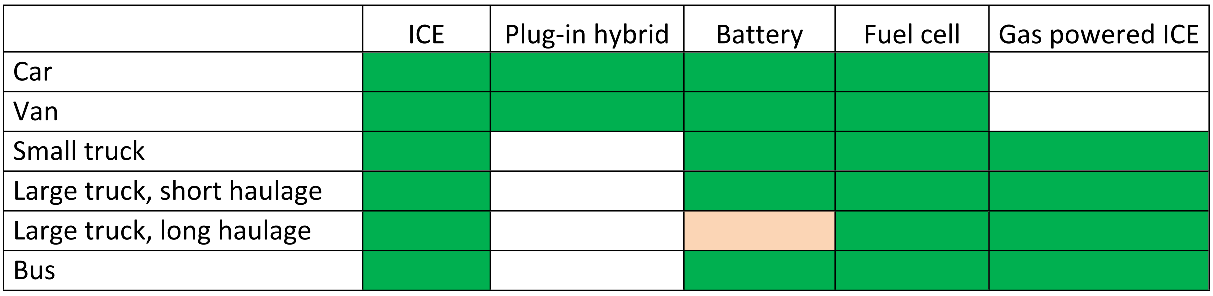


Figure 38 Matrix of powertrains applied for the different road transport demand

Some technologies of vans and buses are limited to give a more realistic development in certain model scenarios, see Table 46. Battery vehicles are highly efficient with low maintenance and fuel costs. However, for heavy-duty applications their current limited range is a strong drawback and can oppose limits of their penetration in heavy-duty segments. Based on the technical performance of the vehicles in current demo projects in Norway, a market penetration of approx. 1% can be achieved [69]. However, rapid technology increase is expected. A forecast to the trucks market share is shown in Table 46.

Table 46 Upper market share limitations of vans and buses

Technology	Market share			
	2018	2020	2030	2040
Battery electric vans		15%	100%	100%
Plug-in vans		1%	100%	100%
Biogas buses		5%	50%	100%
Battery electric Small truck	0%		100%	100%
Battery electric Large truck, short haulage	0%		100%	100%
Battery electric Large truck, long haulage	0%	0%	0%	0%

5.3.4 Existing stock

The existing fleet of vehicles at the start year is modelled as a stock of ICE powertrains, which linearly decreases to zero during a time span equivalent to the vehicle's lifetime. The only exception is the rapid increase in fleets of battery and plug-in hybrid powertrains for TCAR, which has emerged only during the last years. These are defined more specifically as past investments using PASTI and based on the road traffic volumes provided by Statistics Norway [75]. For battery vehicles data between 2012 and 2019 is used, while for plug-in hybrids available data spans between 2016-2019.

The distribution of the transport demand and corresponding vehicle fleet is assumed to be constant over time as per distribution shown in Table 47. In the same Table 47, it is also shown how existing stock of battery vehicles are distributed with a greater density in the southern parts of Norway.

Table 47 Distribution of transport demand and existing stock of battery vehicles over regions

	Transport demand	Battery vehicle distribution
NO1	42%	51%
NO2	24%	21%
NO3	16%	10%
NO4	9%	3%
NO5	9%	15%
Total	100%	100%

5.3.5 Input values

Where possible, data for Klimakur 2030 are used, as this source is being the knowledge ground for studies of how to reduce greenhouse gas emissions in Norway and to have a consistent method for many input data for transport segment in IFE-TIMES-Norway. The disadvantage is that it only presents data for ICE and battery powertrain, while data for other sources needs to be complemented from other sources. When data is complemented, it is more important to simulate the relative change in the parameters between the powertrains than absolute values. Therefore, relative change in parameters with base in ICE powertrain is used for complementary data. Exception has been made for investment costs for trucks, where data from TØI are used as basis.

5.3.5.1 Fuel consumption

In this chapter the different processes/powertrains for the different technologies are presented.
The fuel consumption is taken for vehicles in 2020 and applied for start year, which makes the modelled fuel consumption for start year slightly higher than reality. The fuel consumption of existing stock is based on the one of new cars in the start year, but with slightly increased fuel consumption to match the CO2 emissions for 2018. See last part in this chapter for the comparison. No adjustments are made to the fuel/energy consumption of EV stock.

Passenger cars (TCAR)

The statistics of cars sold during 2017 and 2018 shows approx. even split between small and compact cars and medium, large and luxury cars [76]. The fuel consumption for TCAR-ICE and TCAR-ELC in 2020 is based on the average value of a small and a large representative car in Klimakur 2030 – teknisk notat [17]. The chosen representative cars are VW Golf for a small car and VW Tiguan for a large car. Golf is available both with ICE and battery while Tiguan is available only with ICE. The study however decomposes each car and set an imaginary battery propulsion in VW Tiguan. The weakness of Klimakur 2030 report is that it does not include other relevant powertrains such as plug-in hybrid and hydrogen cars. To have a complete and a consistent dataset, relative relationships between different powertrains and years are taken from an extensive analysis of drivetrains made in modelling program Autonomie by Argonna national laboratory [77]. When applying trends from [77]; the fuel consumption relationship between powertrains and development over time is based on a midsize car, at low technology development and at high cost prediction. In addition, the energy consumption is based on average value from the two driving cycles used in the simulation, Urban Dynamometer Driving Schedule and Highway Federal Emissions Test. The energy demand for fuel cell vehicles is interpreted as very optimistic, thus the fuel consumption of fuel cell cars in start year and in future is taken from Danish Teknological Institut [74]. An overview of the values used are shown in Table 48.

Table 48 Energy consumption for passenger cars (TCAR)

Name in TIMES	Start year		2050	
	kWh/km	Source	kWh/km	Source
TCAR-ICE	0.57	Average small and big car from [17]	0.39	31% improvement from 2020 according [77]
TCAR-ICE_0	0.64	15% increase from new investment		
TCAR-ELC	0.19	Average small and big car from [17]	0.167	12% improvement from 2020 according [77]
TCAR-ELC_0	0.19	Same as new investment		
TCAR-PLUG	0.42	Relative improvement from ICE according to [77]	0.32	24% improvement from 2020 according [77]
TCAR-PLUG_0	0.47	15% increase from new investment		
TCAR-H2	0.33	[74]	0.28	[74]

Vans (TVAN)

There is less literature available regarding vans in comparison with passenger cars, but in large extent they are similar in size. Especially when considering that max gross vehicle weight (GVW) for both types are 3.5 tons and that 71% of total vans vehicle km in Norway during 2019 was made with small vans with max payload of 1 ton [78].

The fuel consumption of ICE and battery vehicles are based on the average value of light and heavy van specified in Klimakur 2030. The light van in Klimakur 2030 is defined to be below 1.7 ton GVW and heavy vans above that limit and below 3.5 ton. It is comparable, even if not the same definition as in SSB. In Table 49, the final values used for powertrains for TVAN in IFE-TIMES-Norway are shown.

Table 49 Energy consumption for vans (TVAN)

Name in TIMES	Start year		2050	
	kWh/km	Source	kWh/km	Source
TVAN-ICE	0.7	Average of light and heavy van from [17]	0.622	Same improvement as for TCAR-ICE
TVAN-ICE_0	0.87	25% increase from new investment		
TVAN-ELC	0.23	Average of light and heavy van from [17]	0.21	Same improvement over time as for TCAR-ELC
TVAN-PLUG	0.52	Same relative improvement as for TCAR-PLUG relative to TCAR-ICE	0.46	Same improvement over time as for TCAR-PLUG
TVAN-H2	0.41	Same relative improvement as for TCAR-H2 relative to TCAR-ICE	0.37	Same improvement over time as for TCAR-H2

Trucks (TTRUCK-S, TTRUCK-LS and TTRUCK-LL)

For trucks and tractor units it is challenging to find a complete dataset which represents the fuel consumption for all the powertrains used and adapted for the Norwegian conditions. Several factors make the Norwegian usage pattern unique, for example: (i) higher max GVW in comparison with EU and USA as default max GVW is 50 tons and in some exceptions up to 60 tons (ii) mountainous landscape with few highways results in low average speed with frequent up and downhills.

The efficiency of ICE vehicles is based on empiric data from almost 900 000 working days in trucks with engines between 200 to 700+ horsepower. This data was gathered in LIMCO project led by TØI and shared with IFE. The received data was than weighted against how the daily milage is distributed in the national fleet (Table 42) and for each truck type as defined previously.

For zero-emission heavy-duty technologies, there is limited experience, which results in a great variation in expected fuel consumption. For example, relative improvement in fuel consumption versus ICE for a battery truck from Klimakur 2030 is similar to fuel cell truck presented by Fulton et.al. [79]. To include the difference in energy loss between a battery and a fuel cell technology, their relative advantage versus ICE are based on Fulton et.al. [79]. A shortage in the work of Fulton et.al. is lack of electric long-haul truck, such as example Tesla Semi. To estimate the improved energy efficiency of such a truck in Norway, the relative improvement for a short-haul truck from fuel-cell to battery is used as reference.

It shall be noticed that for long-haul vehicles in [79] with electric and hydrogen powertrain the advantage to ICE is notably reduced. This is because at steady long-haul driving, the efficiency of ICE increase, while the possibility to regenerate power in electric driveline decreases.

Two long-term trends in goods transport can contribute to reduce the emissions per transported ton of goods and the cost of transport; (i) the emissions and cost per ton goods are reduced if more goods are transported per vehicle which encourages the use of bigger vehicles and (ii) the steady increase in the energy efficiency of the vehicles. The first trend forces the energy consumption per vehicle up as the average vehicle becomes heavier and the second trend decreases the energy consumption per vehicle. As there lies an uncertainty on how the future heavy-duty market will develop with contradicting trends regarding the fuel consumption per vehicle, the energy efficiency for trucks is set constant from start year until 2050.

The values used in IFE-TIMES-Norway based on the sources and assumptions mentioned above is shown in Table 50.

Table 50 Energy consumption for trucks

Name in TIMES	Start year	
	kWh/km	Source
TTRUCK-S-ICE	3.37	Aggregated data from LIMCO [17, 80]
TTRUCK-S-ICE_0	3.94	10% increase from new investment
TTRUCK-S-ELC	1.48	Relative improvement from ICE in a short-haul truck according [79]
TTRUCK-S-H2	2.49	Relative improvement from ICE in a short-haul truck according [79]
TTRUCK-LS-ICE	4.83	Aggregated data from LIMCO [80]
TTRUCK-LS-ICE_0	5.31	10% increase from new investment
TTRUCK-LS-ELC	2.13	Relative improvement from ICE in a short-haul truck according [79]
TTRUCK-LS-H2	3.57	Relative improvement from ICE in a short-haul truck according [79]
TTRUCK-LL-ICE	4.19	Aggregated data from LIMCO [80]
TTRUCK-LL-ICE_0	4.61	10% increase from new investment
TTRUCK-LL-ELC	1.84	Relative improvement as from H2 to ELC short-haul truck according to [79]
TTRUCK-LL-H2	3.10	Relative improvement from ICE in a long-haul tuck according [79]

Buses (TBUS)

The Norwegian Institute of Transport Economics have had close follow up of the national public transport system and its experience of zero-emission technology. Their work published in [69, 81] provides fuel consumption for the complete set of existing technologies (2016-2019), as well as short/middle term technologies with improved ICE engine and more mature battery technology in 2025. Due to the bus segments limited role in the transport sectors total energy consumption, no analysis was made for trends beyond 2025. An overview of the values used is shown in Table 51.

Table 51 Energy consumption for buses (TBUS)

Name in TIMES	Start year		2025	
	kWh/km	Source	kWh/km	Source
TBUS-ICE	4.20	[69]	4.10	[69]
TBUS-ICE_0	4.83	15% increase from new investment		
TBUS-GAS	5.38	Increase relative to ICE Euro IV according to [81]	5.25	Increase relative to ICE Euro IV according to [81]
TBUS-GAS_0	6.18	15% increase from new investment		
TBUS-ELC	2.30	[69]	2.10	[69]
TBUS-H2	3.33	[69]	3.33	[69]

CO_2 emissions in start year

The CO_2 emissions in the start year are adjusted to match the national emissions from road transport in 2018. As in IFE-TIMES-Norway, the existing stock of vehicles are modelled relatively course, and thus there is a small mismatch in numbers, as shown in Table 52.

Table 52 Comparison of CO_2 emissions from road transport in 2018 from Statistics Norway (SSB) [82] and IFE-TIMES-Norway start year

		Statistics Norway	IFE-TIMES-Norway
		Mill. ton CO2	Mill. ton CO2
Car		**4.83**	**4.89**
Light transport		**1.4**	**1.25**
Heavy transport		**2.95**	**3.01**
	TTRUCK-S		0.50
	TTRUCK-LS		1.02
	TTRUCK-LL		0.88
	BUS		0.61
Total emission from road transport except 2 wheelers		**9.18**	**9.16**
2-wheelers		**0.13**	
Total emission from road transport		**9.31**	**9.16**

5.3.5.2 Maintenance costs

The maintenance costs (see Table 53) are based on values specified in Klimakur 2030 [17] for ICE and battery powertrains and adapted to gas, plug-in and fuel cell vehicles. In Klimakur 2030 they are maintained constant until 2030, and in IFE-TIMES-Norway they are also assumed constant until 2050. The only exception for the rule is fuel cell vehicles, and this is explained more in detail below.

The maintenance cost for gas buses is assumed to be the same as for ICE. For plug-in vehicles an average maintenance cost between ICE and battery vehicles is assumed, motivated by decreasing wear of the brake system, but a remaining complex powertrain with many rotating parts. For fuel cell vehicles, the maintenance cost is equal to plug-in vehicles in the start year. Nevertheless, maintenance cost based on fuel cell technology remains a novel technology and might require closer follow up in near term. In the long term the maintenance level is assumed to be comparable with EV.

In Klimakur 2030, the maintenance costs for heavy-duty trucks are not differentiated between battery and ICE powertrains, thereby also no differentiation is made in IFE-TIMES-Norway.

Table 53 Maintenance costs in NOK/km

	Year	ICE	Plug-in hybrid	Battery	Fuel cell	Gas
TCAR	Start year	0.62	0.45	0.28	0.45	
	2030				0.28	
TVAN	Start year	0.65	0.46	0.28	0.46	
	2030				0.28	
TTRUCK-S	Start year	0.98		0.98	0.98	
TTRUCK-LS	Start year	0.98		0.98	0.98	
TTRUCK-LL	Start year	0.79		0.79	0.79	
TBUS	Start year	2.20		1.60	1.90	2.20
	2030				1.60	

5.3.5.3 Investment cost

The VAT and purchase fees are included only for cars as it is expected to account for the cost exposed to the buyer of the vehicle.

Passenger cars (TCAR)

In TØI report “360 graders analyse av potensialet for nullutslippskjøretøy", the car sales are divided into several car type segments and the cost of each segment (small, compact, medium size, large and luxury). The two largest segments of cars sold is compact and medium size cars standing for 43% and 27% of the sales, respectively. [76]

The purchase price of ICE and EV vehicles are based on Klimakur 2030 [17]. The costs are, as with fuel consumption, based on a representative car and the costs used in IFE-TIMES-Norway is an average value between a small and a large car. For more detail information about the representative cars see chapter “5.3.5.1 Fuel consumption”.

For powertrains other than ICE and battery, the costs are taken from TØI report “360 graders analyse av potensialet for nullutslippskjøretøy" based on weighted purchase cost from all the car segments.

Klimakur 2030 provides cost development between 2020 and 2030. TØI report "360 graders analyse av potensialet for nullutslippskjøretøy" provides costs in 2019 and 2025. The costs from TØI report are adjusted to start year and 2030, respectively.

The summary of the used costs for TCAR in IFE-TIMES-Norway excluding VAT and fees is shown in Table 54.

The VAT of 25% is assumed to be paid both for ICE and plug-in vehicles, while the one-time fee is assumed to be 91160 NOK for ICE and 2877 NOK for Plug-in vehicle based on values provided by [76]. To include these values in TIMES, the fees are added upon the vehicle cost and thereafter converted to input for TIMES considering the vehicles average annual mileage.

Table 54 Investment costs for TCAR exclusive taxes and fees

Name in TIMES	Start year		2030	
	NOK	Source	NOK	Source
TCAR-ICE	229,100	Average small and large car [17]	241,643	Average small and large car [17]
TCAR-ELC	480,500	Average small and large car [17]	248,489	Average small and large car [17]
TCAR-PLUG	306,381	Trend relative to ICE from [76]	287,546	Trend relative to ICE from [76]
TCAR-H2	765,167	Trend relative to ICE from [76]	370,661	Trend relative to ICE from [76]

Vans (TVAN)

Klimakur 2030 provides cost for a large and small van for both ICE and battery powertrains. While for other powertrains, the same relative cost trends as for TCAR is applied based on the similarities between TVAN and TCAR discussed in chapter "5.3.5.1 Fuel consumption". The summary of the costs for TVAN in IFE-TIMES-Norway is shown in Table 55.

The one-time fee is indicated to be 24 000 NOK for small vans and 69 000 for large vans for ICE vans [17]. In IFE-TIMES-Norway, an average of 46 500 NOK per ICE vehicle is used. For plug-in vehicles, the fee is assumed to be so low that it is assumed to be neglectable.

Table 55 Investment costs for TVAN exclusive taxes and fees

Name in TIMES	Start year		2030	
	NOK	Source	NOK	Source
TVAN-ICE	230,500	Average small and large van [17]	236,240	Average small and large van [17]
TVAN-ELC	506,000	Average small and large van [17]	248,489	Average small and large van [17]
TVAN-PLUG	308,254	Trend relative to ICE from [76]	281,116	Trend relative to ICE from [76]
TVAN-H2	769,842	Trend relative to ICE from [76]	362,373	Trend relative to ICE from [76]

Trucks (TTRUCK-S, TTRUCK-LS and TTRUCK-LL)

The investment cost for 2020 and 2030 are based on data received from TØI. They have built up the dataset through cost decomposition of different parts of the vehicle. In addition, a premium cost is added for novel powertrains. This additional cost can to some extent be assigned to R&D. The costs of 2020 are quality checked by known truck OEM.

In IFE-TIMES-Norway, it is assumed that a continues development of investment costs for new drivetrains (fuel cells and batteries) continues also after 2030, while investments in ICE and GAS powertrains are assumed to be constant. Fulton et.al. [79] predicts that by 2050 the fuel cell and battery trucks investment costs will reach almost parity with ICE and their relative cost differences are applied.

A simplification has been made by assuming the same investment cost for TTRUCK-LS and TTRUCK-LL, where it would be reasonable to assume that trucks who drive longer would need larger batteries and hydrogen tanks, thus be more expensive relative to ICE. As battery and fuel cell trucks still are in their infancy, it is hard to find such a distinction in the literature. It shall be noted that battery vehicles are not included for TTRUCK-LL in a typical reference scenario due to the uncertainty of its technical feasibility.

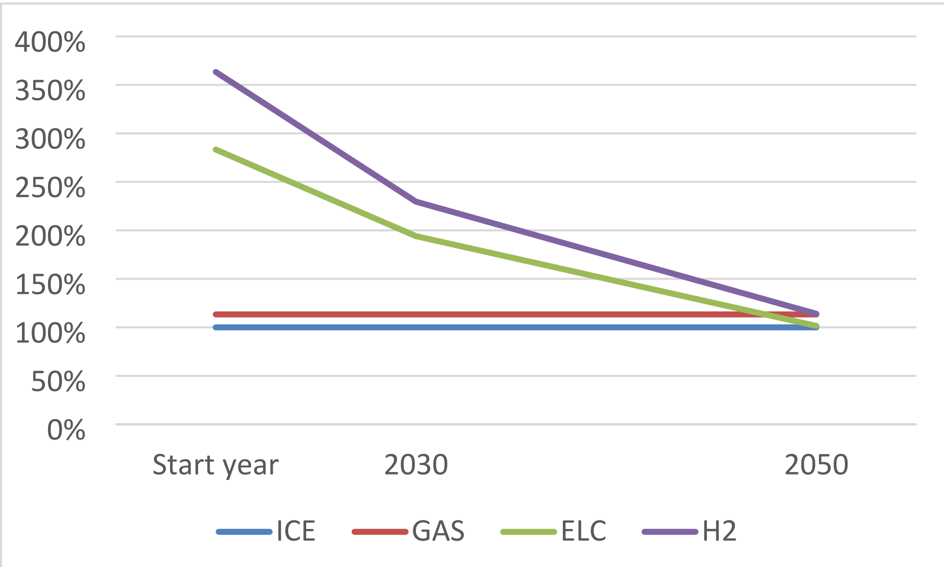


Figure 39 Investment cost development for TTRUCK-S

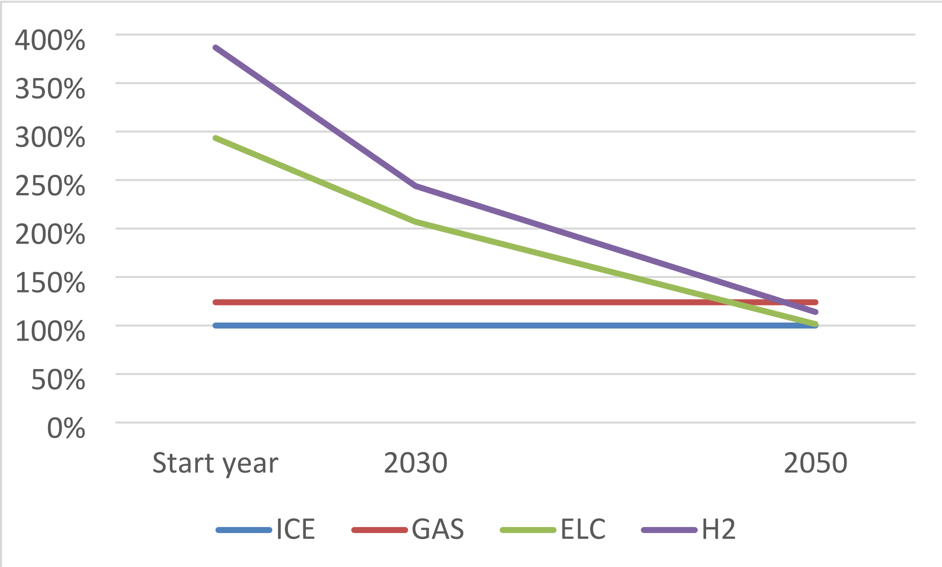


Figure 40 Investment cost development for TTRUCK-LS & LL

By 2020 the large-scale deployment of battery and hydrogen powertrains are still lacking, however strong activity within this field is noted with announcements of several models being introduced during the coming year. Therefor the starting year at which they can be deployed in the model has been adjusted as presented in Table 56.

Table 56 Starting year for investment in battery and hydrogen powered trucks and tractor units.

Type of truck and powertrain	Starting year
TTRUCK-S-ELC &TTRUCK-LS-ELC	2022
(TTRUCK-LL-ELC)	2100/2025
TTRUCK-S-H2	2025
TTRUCK-LS-H2 & TTRUCK-LL-H2	2025

Buses (TBUS)

The investment cost of buses until 2025 is based on TØI report “Klima-og miljøvennlig transport frem mot 2025” [83]. The cost trend of ICE bus and the relative cost to ICE for the other powertrains in 2050 is based on cost development of urban buses from Fulton et.al. [79] from UCDavis. The summary of the used costs for TBUS in IFE-TIMES-Norway is shown in Table 57.

Table 57 Investment costs for TBUS exclusive taxes and fees

Name in TIMES	NOK	Source
Start year		
TBUS-ICE	2,000,000	[83]
TBUS-GAS	2,200,000	[83]
TBUS-ELC	4,500,000	[83]
TBUS-H2	8,000,000	[83]
2025		
TBUS-ICE	2,000,000	[83]
TBUS-GAS	2,200,000	[83]
TBUS-ELC	3,000,000	[83]
TBUS-H2	4,000,000	[83]
2050		
TBUS-ICE	2,116,000	Relative change from 2025 according to [79]
TBUS-GAS	2,435,000	Trend relative to ICE from [79]
TBUS-ELC	2,116,000	Trend relative to ICE from [79]
TBUS-H2	2,290,000	Trend relative to ICE from [79]

5.3.5.4 Lifetime and annual mileage

Lifetime and annual mileage are two additional input variables used in IFE-TIMES-Norway and which are correlated. In general, vehicles annual mileage is highest the first years and drops considerably with age. In addition, vehicles of a given purchase year are continuously phased out from the fleet. In IFE-TIMES-Norway, these parameters are simplified with a constant annual mileage each year and with equal lifetime for each type of vehicles.

To find a fixed representative values for a continuous process of vehicle phase-out and reduced mileage over time, Statistics Norway data was used to look at how the share of annually mileage where accumulating with the age of vehicles, see Figure 41. The lifetime of vehicles in IFE-TIMES-Norway is set to a threshold of age at which approx. 90% of the yearly road traffic volume is covered.

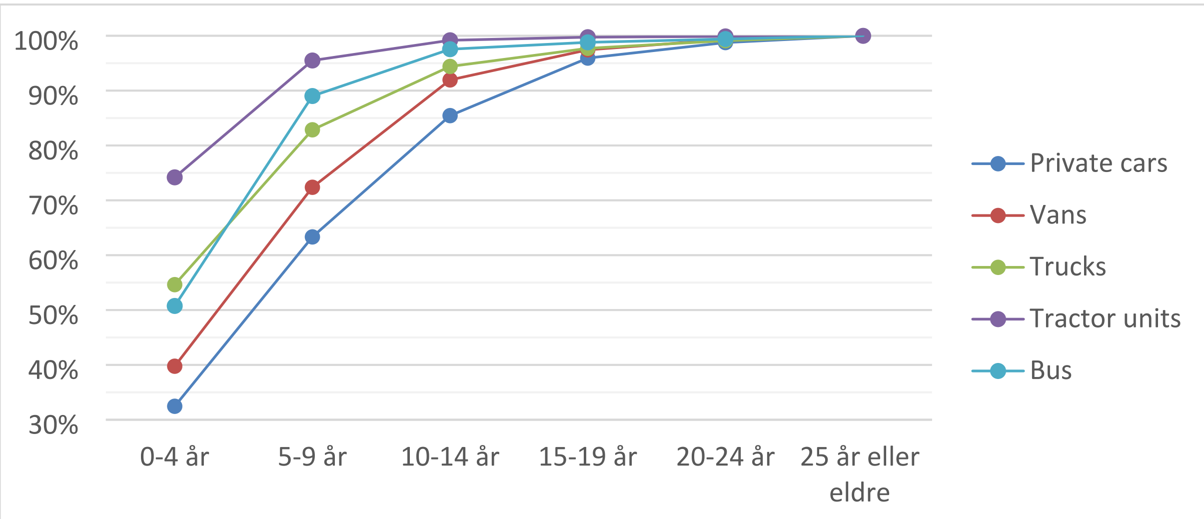


Figure 41 Accumulated traffic volume of each vehicle type depending of age, based on data from [78]

The Statistics Norway database, which is used to select vehicle lifetime, offers both the road traffic volume in absolute values and an average yearly mileage per vehicle. From this data, it was possible to find the number of vehicles in each time bin. The average annual mileage is based on the road traffic volume divided by the number of vehicles, including only traffic volume and vehicles during the assumed vehicle lifetime in IFE-TIMES-Norway. The resulting annual mileage per vehicle is shown in Table 58.

The available dataset from Statistics Norway is distinguishing trucks between tractor units and all other trucks, while IFE-TIMES-Norway follows another division of trucks where both regular trucks and tractor units can be of either TTRUCK-LS and TTRUCK-LL type, depending on their typical daily mileages. To define the values for TTRUCK-LL, it is assumed that trucks drive a bit higher annual mileage and that their lifetime is a bit shorter than tractor units, hence some of the tractor units have lower annual mileages and by that sorted under TTRUCK-LS. While for TTRUCK-S and TTRUCK-LS the opposite is made based on the data provided for the rest of the trucks. The assumptions are shown in Table 58.

The simplification of vehicle lifetime and average annual mileage has some shortcomings, such as underestimating usage of newly invested vehicles (new technology) and overestimated usage of vehicles at the end of its lifetime in IFE-TIMES-Norway (old technology). In addition, the model omits usage of old and very old vehicles which are past the lifetime set in IFE-TIMES-Norway.

Table 58 Lifetime and annual mileage used in IFE-TIMES-Norway

Vehicle type	Lifetime (years)	Average annual mileage (km)
TCAR	17	13 200
TVAN	15	15 300
TTRUCK-S	15	30 000
TTRUCK-LS	13	35 000
TTRUCK-LL	6	90 000
TBUS	10	41 800

5.3.6 Growth limitation

By default, TIMES select the technology to invest in based on the lowest lifetime cost option available. It means that once a new technology becomes the cheapest option, the entire investment in new capacity is shifted to this new technology. A 100% switch between vehicle powertrains from one year to another is assumed to be unrealistic for vehicle sales and thereby a limitation is placed on the growth in new capacity for the different powertrains. These limitations are made with the help of NCAP, GROWTH user constraint.

The calibration of the growth constrain is inspired by TØI analysis made by stock-flow vehicle fleet model [84]. The year-to-year growth of a technologies' market share will vary as new technologies tend to conquest a market first with early movers, then the majority is onboarding, and at last the laggards are adopting. Consequently, new technologies' market share will have a S-form, as seen in Figure 42. On the other hand, the growth constraint functionality in TIMES is based on a constant year-to-year growth limitation value, which provides an exponential growth of market share over time.

To make the best possible approximation for the growth constraint; the initial investment in the new technology is allowed to take a relatively large share of the total new investments and the annual growth rate is selected to fit best where the new technology share of new investments increase most rapidly. The average growth increase is selected as the averaged year-to-year growth value when new investment share of zero emissions is increased from 10% to 90% for the three technologies shown in Figure 42. The growth constrain is adopted to both electric and hydrogen powertrains, while it is assumed that the growth for individual technologies and vehicle types can be double as fast. It is especially relevant for trucks as they are subdivided into several subcategories and that they are the most relevant pretendent for both battery and fuel cell technology in the road transport.

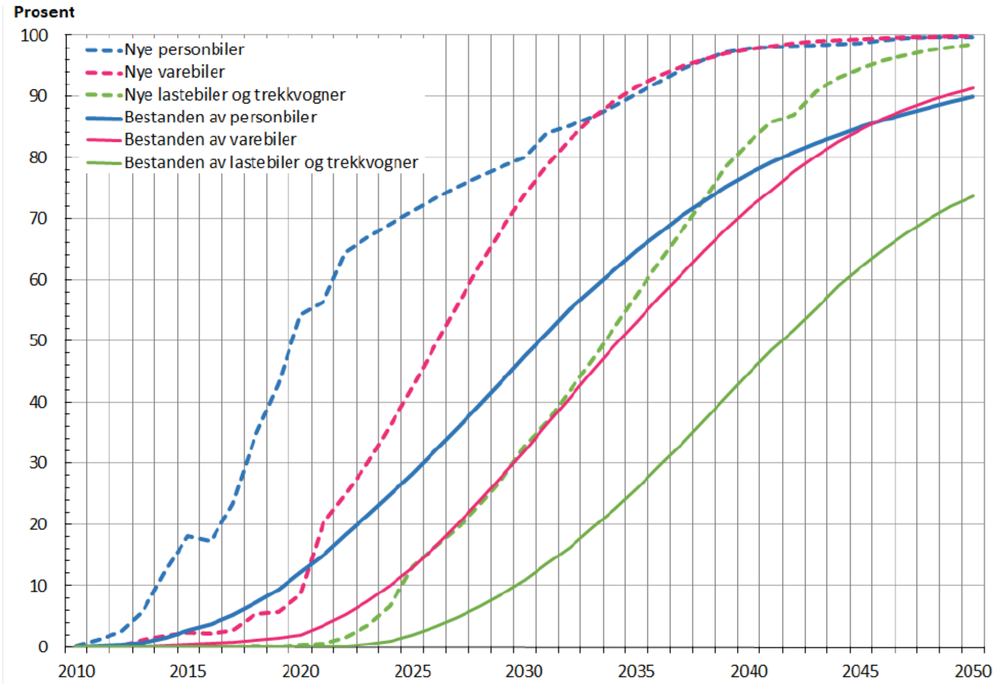


Figure 42 The zero emission vehicles share of new investment and fleet in the fast decarbonization scenario presented in [84]

This growth constrain is also adopted to conventional technologies, to limit a possible high fluctuation in their market share as well. So, for technologies with existing stock, the user constrain comes into force two years after the stock is defined either by STOCK or PASTI variable in TIMES. Thereby these technologies can calibrate what is a typical amount of new investments in each technology before the user constrain is applied. While for technologies without an existing stock, a predefined first investment is allowed, so called seed value. It is sized to represent 10% of total new investment needed within one modelling period.

5.3.7 Charging infrastructure for EV's

All electrical vehicles depend on available charging infrastructure, which brings an additional cost to the system in comparison with current well-established petrol filling station infrastructure. For private vehicles and vans, three different charging types are included: Residential, Commercial and Fast charging. Both residential and commercial charging occur by slow chargers. The Commercial charging is defined as slow charging close to commercial buildings, with the intention to represent that the car is charged at work. The typical usage pattern over a day is shown in Figure 43. In the base case, it is assumed that passenger cars charge 75% of the time at residential buildings, 15% of the time at commercial buildings, and 10% of the time by fast charging. For vans, it is assumed that charging occurs at home or at commercial buildings (50% each), using the same type of charger.

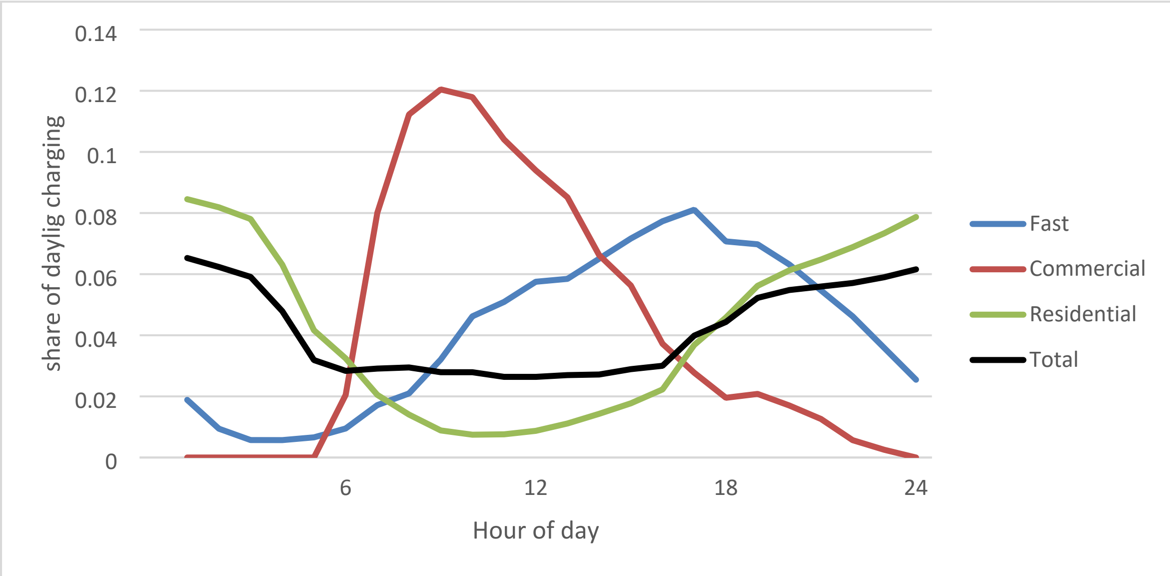


Figure 43 Daily usage pattern for EV charging and disaggregated for different charging locations. Derived from [85]

For heavy-duty vehicles, both slow and fast charging are considered. Both profiles are shown in Figure 44 and share between slow and fast charging for each truck type is shown Table 59. As majority of trucks below total GVW of 50 ton drives short distances, they are assumed to mainly utilize slow chargers. TTRUCK-LS (total GVW ≥50 ton & <300 km/day) are assumed to entirely depend on slow chargers. On the other hand, TTRUCK-LL (total GVW ≥50 ton & >300 km/day) are assumed to depend equally much on slow and fast chargers.

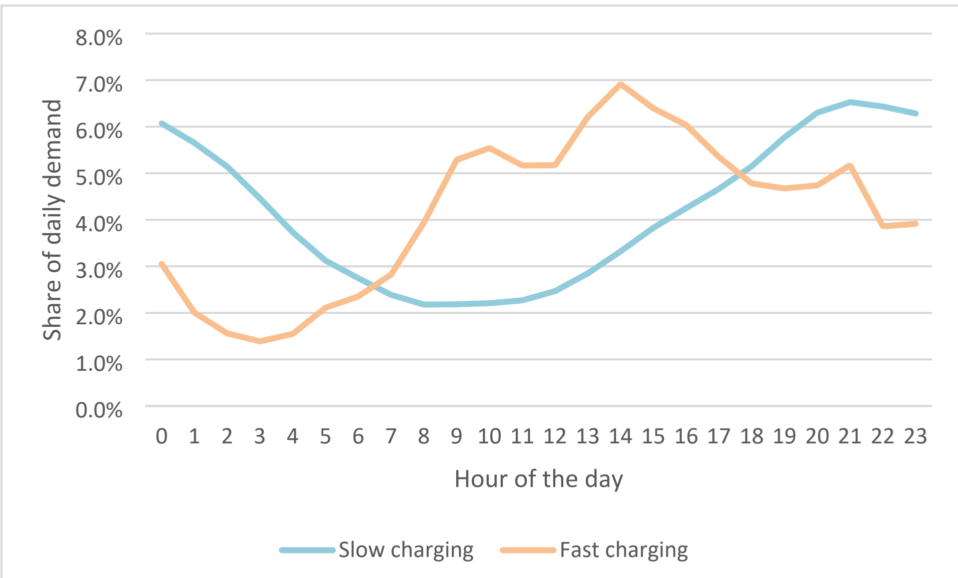


Figure 44 Slow and fast charging profiles based on data gathered within Limco project [86]

Table 59 Share of energy supplied to electric trucks from slow and fast chargers.

	Slow charging	Fast charging
TTRUCK-S	75%	25%
TTRUCK-LS	100%	
TTRUCK-LL	50%	50%

The cost of chargers are based on data published in Klimakur 2030 report [17]. For residential and commercial chargers, the costs are based on a <11kW installation with assumed average output of 7kW. For fast charging, a 50kW charger is assumed at the start year, which is fully replaced by a 150kW charger in 2025.

For heavy-duty charging, there is limited data. In Klimakur, the cost of a 50 kW charger, representing a slow charger, is provided. The cost from Klimakur 2030 report is complemented with a grid connection fee, as the first chargers installed at a logistic central or similar will probably not need grid enforcement. But when larger volumes will need to be deployed, a need for grid reinforcement will be required. There are very limited data for fast charging of heavy-duty truck. In IFE-TIMES-Norway, the cost is expected to be closer to the costs and performance of a 350 kW light duty charger, compared to a pantograph type charger which is currently installed to serve fixed route electric buses. As buses represent a small share of road traffic, they are utilizing the same charging infrastructure as trucks in the model and with a flat charging demand profile.

The main charger unit, either it is onboard or external, rectifies electricity from AC to DC, and transform it between different voltage levels. In addition, energy is required for its control unit. Empiric studies show that a low power output built-in charger for EV's has an efficiency of approx. 80% [87, 88]. Various producers of fast chargers specifies an efficiency of approx. 90% at optimal temperature of approx. 25°C, but is considerably lower at low temperatures [89].

A slow charger will typically be installed to charge a specific vehicle for a long period of time (8-12 h). When including days when the vehicle will need only limited charging or if it is standing still, the chargers overall utilisation rate will be further reduced. On the other hand, a fast charger will be serving many vehicles, but only for a limited amount of time. As such, the charger is designed for a peak demand which occurs occasionally, while low demand periods, e.g., at night, are reoccurring frequently, causing relatively low utilisation rates. The annual utilisation rate for fast chargers is fixed to 30%, inspired by vehicle passage counts at Hanestad and Gol and how they vary throughout the year. For slow charging, the annual utilisation rate is set to 25%, which means that each charger on average charges vehicles for 6 hours every day.

The lifetime is assumed and needs to be reviewed later.

Table 60 Type of chargers used in IFE-TIMES-Norway and their characteristics. Based on [17, 87, 89] and own assumptions.

	Year	Light-duty			Heavy-duty	
Type of charger		Residential	Commercial	Fast charging	Slow charging	Fast charging
Commodity used		ELC-LV-RES	ELC-LV-COM	ELC-LV-COM	ELC-LV-COM	ELC-LV-COM
Efficiency		80%	80%	90%	90%	90%
Equipment and installation cost (NOK/kW)	2018	2857	2857	7000	5000	3400
	2025			3000		
Grid connection fee (NOK/kW)	2018			5000	2000	1000
	2025			2000		
Lifetime (year)		15	15	15	15	15
Utilisation factor		25%	25%	30%	25%	30%

5.4 Non-road transport

5.4.1 Structure and demand

Other transport than road transport is transport by rail, sea and air. In addition, a category gathering the rest of transport demand is included in “other transport”. Demand is modelled as an energy demand (GWh/year) in these categories. The demand projection is presented in Figure 45.

Energy use of domestic air transport in the base year is divided in the five regions based on population in 2018. Development in passenger km in NTP 2022-2033 [71] is used for the demand projection of air transport. Sea transport is divided in passenger transport, fishing and other sea transport. The projection of passenger sea transport is based on the development of passenger km in NTP 2022-2033 [71]. For the two other sea transport categories, the total development of freight transport by sea is used. The projection of rail transport is 50% based on development of passenger transport and 50% on freight transport. The rest category is assumed to develop according to the increase in population of Statistics Norway 2020 (MMMM alternative).

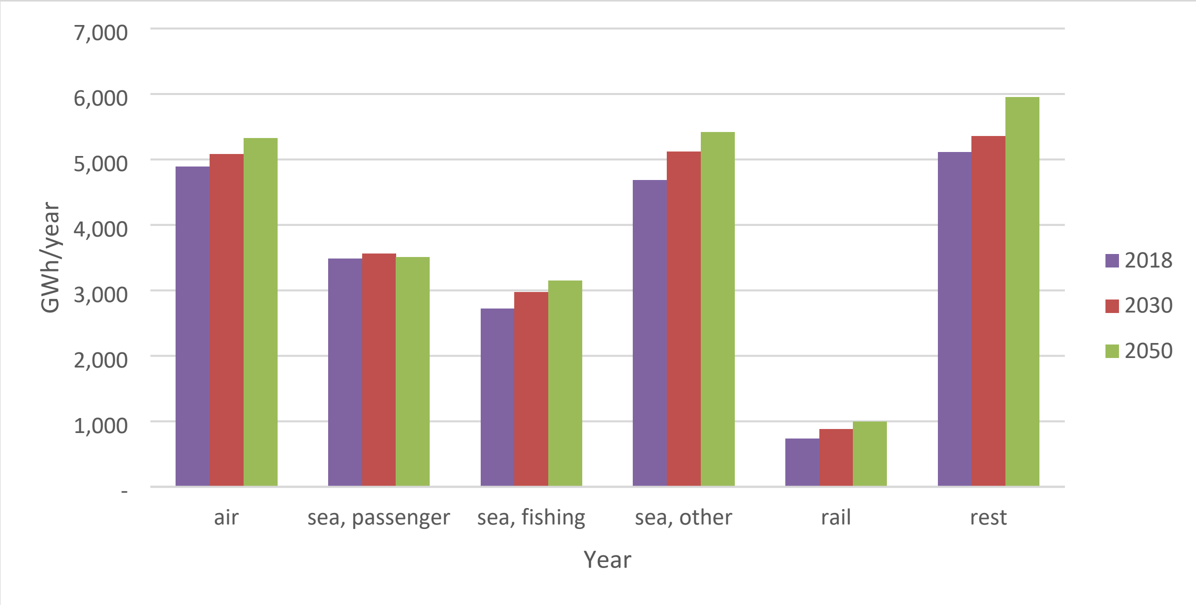


Figure 45 Energy demand of non-road transport in 2018, 2030 and 2050, TWh/year

5.4.2 Modelling of rail, air and other transport

Energy use in rail transport and other transport is modelled as a share of different energy carriers. In the regions NO1, NO2 and NO5, the railway can use 100% electricity. In region NO3, the maximum electricity share for railway is 8% and in NO4 the maximum electricity share is 4%. This share is kept fixed until 2050. When electricity is not used, railway can use an optional mix of fossil and biofuel.

In other transportation, only fossil fuel blended with 5% biofuel can be use in the base year. From 2040 a maximum share of 67% electricity and 100% biofuels can be used, linearly increased from the base year. The efficiency of electricity is assumed to be three times better than the use of liquid fuels.

Air transport uses fossil fuels in the base year and a minimum share of 10% biofuels is included in 2020, increasing to 30% in 2050. Electricity can be used in air transport after 2025, linearly increasing to 20% in 2040. Air transport using electricity is assumed to be twice as effective as fossil or biofuels. Cost data is not included in the modelling of air transport.

5.4.3 Maritime transport

The current energy demand and emissions from maritime sector in the start year is received from Statistics Norway divided between coastal transport and fishing. To estimate potential for decarbonisation, it is crucial to disaggregate as maritime transport varies greatly in ship designs and sizes as well as operation patterns. These variating parameters are affecting how well different zero-emission fuels and technologies can penetrate the different ship segments.

From the fuel bunkering data, it is not trivial to track how large share of the fuel bunkered in Norway is used for this purpose, as the maritime sector is very international. Vessels can easily change land of operation or bunker abroad while having main activity in coastal transport or fishing in national waters.

Another shortcoming is the ability to distinguish what type of vessel is bunkering as common bunkering infrastructure can be used, including fishing vessels. Additional protocol needs to be implemented to disaggregate the data to fishing and other vessels. So, the data provided gives both uncertainty if the bunkered fuel is used for domestic transport and fishing and how large share of it is used by fishing vessels. As a result, the energy consumption and emissions for fishing vessels has variated strongly between different methods used by Statistics Norway as well as by other sources. [90, 91]

The ship movement and by that indirectly their energy demand and emissions can also be monitored through Automatic Identification System (AIS) data. It can provide data for all vessels within a given geographical area, such as the Norwegian exclusive economic zone (in Norwegian: Norsk Økonomisk Sone or NØS). However, not all of them are operating for coastal transport. There are other shortcomings of AIS data, as the requirement of installing it applies only for certain size vessels. For fishing vessels, the limit goes at 15 meters and the large majority of fishing vessels are by that excluded from the AIS dataset [17].

In [92], the emissions from AIS data where reviewed within NØS. When only considering vessels spending 80% or more of their time inside NØS and adding an estimate of 240 kton CO_2 equivalents for fishing vessels not covered by the AIS system [93], a close match was achieved with emissions data provided by Statistics Norway as seen in Table 61. The AIS data is presented per ship-type, which is seen as too detailed resolution for the IFE-TIMES-Norway model. Therefore, the maritime sector is aggregated to three ship types, divided by colours, and numbering in the same table.

Table 61 Comparison of CO2 emissions from maritime sector based on bunkering and AIS data (compensated for fishing vessels without AIS equipment with 240 kton). Also shown how the different ship types are aggregated in IFE-TIMES-Norway

	Statistics Norway (kton CO_2)	DNV GL (kton CO_2)	Share of emissions	Grouping
Passanger ships		831	27%	1
High speed ferries		139.8	5%	1
Cruise		19	1%	1
Fishing vessels		526+240	25%	2
Offshore vessels		711	23%	3
Other special use vessels		117	4%	3
Aquaculture		148	5%	3
Freight ships		199	6%	3
Wet & dry bulk		159	5%	3
6.3.1.0 Navigation - coastal traffic etc.	2713		88%	
6.3.2.0 Navigation - fishing	378		12%	
Sum	**3091**	**3090**		

In the AIS data above, emissions from cold ironing in harbours are not included.

To arrive to decomposition of the maritime fleet energy demand, following simplifications are made:

- The emissions for each ship type for coastal transport and national fishing as presented in Table 61 **is proportional** to the energy demand provided by Statistics Norway. Consequently, the lower emissions due to usage of LNG is overseen.
- The natural gas consumption is assumed to be equal between passenger vessels and other ship types.
- In Statistics Norway, the energy demand for fishing industry also included electricity consumption of 224 GWh in 2018. This demand is excluded as it most probably is assigned to fishing farms or other onshore infrastructure.

The main fuels used in the maritime sector today is liquid (MGO and MDO) and gas (LNG) based fossil fuels. Alternative propulsion fuels considered in IFE-TIMES-Norway are batteries and hydrogen for short distance trips and ammonia for deep-sea trips. Liquide hydrogen is also a potential fuel for use in maritime sector, but as it is largely overlapping the usage of ammonia, the latter is chosen to represent hydrogen derivates in deep-sea shipping.

The technology options in IFE-TIMES-Norway and the max share of each technology are shown in Table 62. Due to hydrogen and ammonia immaturity as a maritime fuel, they are only available from 2025. The max market share of each technology for passenger vessels are based on work developed in HyInfra project [94], while for the other two ship types they are based on best guess when considering the ship sizes and trip lengths. The max share remains constant after 2040.

Table 62 Max share of each fuel to serve the maritime demand. Linear interpolation is used for years between inputs

Group	Type of vessel	Year	Fuel used/propulsion system				
			ICE	LNG	Battery	H2	Ammonia
1	Passenger vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030		86%	49%	13%	38%
		2040		86%	49%	13%	38%
2	Fishing vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030			5%	5%	5%
		2040		50%	25%	25%	50%
3	Other vessels	2018	no limits	0%	0%		
		2025				0%	0%
		2030			5%	5%	5%
		2040		90%	10%	10%	90%

Input values

The current fossil fuels are consumed onboard in large and highly efficient (~45-50%) internal combustion engines (ICE). For future fuels, ammonia is also assumed to be consumed in ICE while hydrogen in PEM fuel cells. For both of these new fuels, the energy efficiency is assumed to be similar to conventional ICE. On the other hand, systems based on battery systems is assumed to have efficiency of 80%.

Since hydrogen to Ammonia pathway is not yet included in IFE-TIMES-Norway, the additional efficiency lost from hydrogen to ammonia is included in form of relative efficiency reduction of 17%.

As an intent to represent the investment costs related to energy consumption by the maritime sector, a typical ship type was selected for group 1 based on energy consumption [95] and 3 based on largest emissions or energy consumption (Table 62). A representative size and its investment costs were identified as well as the fleet size of the specific vessel. Thereafter based on assumed energy consumption for the specific vessel type a cost per demand in GWh was identified. The assumptions and results can be seen in Table 63.

Fishing vessels size varies greatly and with that also their costs and energy demand. It was not possible to identify how the energy demand is distributed among the different sizes of the vessels and thereby impeding to couple investment costs to energy demand. Thereby, they are assigned the same investment cost as passenger vessels per annual energy consumption. Even higher value could be expected as not all fishing vessels can work constantly throughout the year as for example ferries or offshore vessels and thereby a lower energy demand per vessel.

Table 63 Investment costs for representative ship technology for maritime demand group 1 and 3

Group	1	3
Type of vessel	Passenger vessels	Other vessels
Example design	Ro Ro Ferry	Platform Supply Vessel (Offshore vessel)
Size [93]	1900 GT (PBE 70)	5080 DWT
Fleet size [93]	203	122
Annual energy consumption (GWh)	856	987
Specific energy consumption (GWh/ship)	4.2	8.1
CAPEX (kNOK/ship)	100'000 [96]	180'000 [97]
CAPEX (kNOK/(GWh/year))	23'728	22'260

Regarding investment in propulsion systems using other fuels, DNV-GL estimates that investment in an LNG ship is 20% more expensive [98]. For the other fuels and propulsion systems, it is very hard to obtain their additional investment costs and their costs are assumed to be 50% higher than for conventional ICE system today. By 2030 their extra costs are assumed to be reduced to 20% higher than ICE.

The lifetime of all ship groups is assumed to be 25 years. Even if ships can live considerably longer, their capacity factors in average are assumed to be higher for newer vessels and that older ships to large degree are sold to other countries. With the ship's long lifetime, it is usual to make retrofits and consider their second-hand. In this simplified approximation to the maritime demand, these aspects are overseen.

6 Final remarks

This report describes the basic version of IFE-TIMES-Norway as of December 2022. The model is continuously under development. In different projects and analyses, scenario files with other data are included. Some examples of projects and analyses can be found in:

- ITEM (Itegrated Transport and Energy modelling) IFE-E-2021-002.pdf (unit.no) and Modelling the interaction between the energy system and road freight in Norway | Elsevier Enhanced Reader [99]
- ASSETS (Assessment of the value of Flexibility Services from the Norwegian Energy System) Stochastic modelling of variable renewables in long-term energy models: Dataset, scenario generation & quality of results - ScienceDirect
- Norwegian Energy Roadmap Bidirectional linkage between a long-term energy system and a short-term power market model (unit.no)
- ETSAP A Scandinavian Transition Towards a Carbon-Neutral Energy System | SpringerLink
- Flexbuild Winners and losers of end-use flexibility in the Norwegian energy system
- NTRANS Transition pathways as “inter-disciplinary meeting place”

7 References

1. IEA-ETSAP. *Energy Technology Systems Analysis Program*. Available from: www.iea-etsap.org.
2. IEA-ETSAP. *IEA-ETSAP Energy Systems Analysis Tools*. 2020; Available from: https://iea-etsap.org/index.php/etsap-tools.
3. KanOrs. *VEDA Support*. 2020; Available from: https://support.kanors-emr.org/#VEDA-FE/Homepage.htm.
4. Loulou, R., et al., *Documentation for the TIMES Model - Part I*. 2005: Energy Technology Systems Analysis Programme.
5. Loulou, R., et al., *Documentation for the TIMES Model - Part II*. 2005: Energy Technology Systems Analysis Programme.
6. Loulou, R., et al., *Documentation for the TIMES Model - Part III*. 2005: Energy Technology Systems Analysis Programme.
7. Janis Danebergs; E Rosenberg: P Seljom: L Kvalbein: K Haaskjold, *Documentation of IFE-TIMES-Norway v2, IFE/E-2021/005*. 2021, Institute for Energy Technology.
8. Loulou, R. and A. Lehtila *Stochastic Programming and Tradeoff Analysis in TIMES. TIMES Version 3.9 User Note*. 2016.
9. Ringkjøb, H.-K., et al., *Short-term solar and wind variability in long-term energy system models - A European case study.* Energy, 2020. **209**: p. 118377.
10. Seljom, P. and A. Tomasgard, *Short-term uncertainty in long-term energy system models — A case study of wind power in Denmark.* Energy Economics, 2015. **49**(0): p. 157-167.
11. Seljom, P., et al., *The impact of Zero Energy Buildings on the Scandinavian energy system.* Energy, 2017. **118**: p. 284-296.
12. Ringkjøb, H.-K., P.M. Haugan, and A. Nybø, *Transitioning remote Arctic settlements to renewable energy systems – A modelling study of Longyearbyen, Svalbard.* Applied Energy, 2020. **258**: p. 114079.
13. Elvia. *Nettleie bedrifter og næring*. 2021 [cited 2021; Available from: https://www.elvia.no/nettleie/alt-om-nettleiepriser/nettleiepriser-for-bedrifter-og-naering/.
14. NVE. *Nettleiestatistikk*. 2022 [cited 2022; Available from: https://www.nve.no/reguleringsmyndigheten/publikasjoner-og-data/statistikk/nettleiestatistikk/.
15. Stian Backe, et al., *EMPIRE: An open-source model based on multi-horizon programming for energy transition analyses.* SoftwareX, 2022. **17**.
16. Finansdepartementet, *Skatter, avgifter og toll 2021*, Finansdepartementet, Editor. 2020, Regjeringen.
17. Miljødirektoratet, *Klimakur 2030, tiltak og virkemidler mot 2030 - Teknisk notat*. 2019: Miljodirektoratet.no.
18. NVE, *Kostnader i energisektoren*. 2017, NVE.
19. NVE, *Langsiktig kraftmarkedsanalyse 2019-2040, NVE-rapport Nr 41/2019*. 2019.
20. NVE, *Analyse og framskrivning av kraftproduksjon i Norden til 2040, NVE-rapport Nr 43/2019*. 2019.
21. NVE, *Ny kraftproduksjon 1. kvartal 2020*. 2020.
22. Teknisk Ukeblad, *Det nye vannkraftverket skal få 15 prosent mer energi fra de samme vannmagasinene - Nå åpner Lysebotn 2*. 2018.
23. Wolfgang, O., et al., *Hydro reservoir handling in Norway before and after deregulation.* Energy, 2009. **34**(10): p. 1642-1651.
24. NVE. *Vindkraftdata*. 2020; Available from: https://www.nve.no/energiforsyning/kraftproduksjon/vindkraft/vindkraftdata/.

25. NVE. *Konsesjonssaker*. 2019; Available from: https://www.nve.no/konsesjonssaker/.
26. International Renewable Energy Agency (IRENA), *Future of wind: Deployment, investment, technology, grid integration and socio-economic aspects*. 2019.
27. Katrine Stenshorne Berg, M.C., Tale Eirum, Sissel Belgen Jakobsen, Nils Henrik Johnson, Sigrun Kavli Mindeberg, Karen Nybakke, Gudmund Synnevåg Sydness, *Havvind - Strategisk konsekvensutredning*. 2012, NVE.
28. Thorud, B. and M.S. Dale, *Lansering av nøkkeltall for det norske solcellemarkedet i 2019*. 2020.
29. Multiconsult, *Hvordan ser et solkraftverk ut? Hva er mulighetene?*, Bjørn Thorud, Editor. 2021, NVE.
30. Bouckaert, S., et al., *Net Zero by 2050: A Roadmap for the Global Energy Sector*. 2021.
31. NVE. *Kostnader for kraftproduksjon*. 2021 [cited 2021 9 September]; Available from: https://www.nve.no/energi/analyser-og-statistikk/kostnader-for-kraftproduksjon/?ref=mainmenu.
32. Pfenninger, S. and I. Staffell, *Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data.* Energy, 2016. **114**: p. 1251-1265.
33. Staffell, I. and S. Pfenninger, *Using bias-corrected reanalysis to simulate current and future wind power output.* Energy, 2016. **114**: p. 1224-1239.
34. Sartori, I., et al., *Flexbuild Annual Report 2. Technical report with results analysis.* SINTEF Fag, 2022.
35. Cole, W., A.W. Frazier, and C. Augustine, *Cost Projections for Utility-Scale Battery Storage: 2021 Update*. 2021, National Renewable Energy Laboratory (NREL).
36. *The longest electricity cable in the world is operational*. 2008 [cited 2020; Available from: https://web.archive.org/web/20110727130201/http://www.norned-auction.org/news/newsitems/The_longest_electricity_cable_in_the_world_is_operational.aspx.
37. Mikkelsen, S.D. *130 mio. euro til ny teknologi på Skagerrak 4*. 2011 [cited 2020; Available from: https://web.archive.org/web/20110216015807/http://www.energinet.dk/DA/ANLAEG-OG-PROJEKTER/Nyheder/Sider/130mioeurotilnyteknologipaaSkagerrak4kabel.aspx.
38. *The world's longest interconnector gets underway*. 2015 [cited 2020; Available from: https://web.archive.org/web/20150328234545/http://www2.nationalgrid.com/Mediacentral/UK-Press-releases/2015/The-world-s-longest-interconnector-gets-underway/.
39. *UK-Norway link bags EU grant*. 2017 [cited 2020; Available from: https://renews.biz/106040/northconnect-scores-eu-cash/.
40. *NordLink*. [cited 2020 28.09]; Available from: https://web.archive.org/web/20200803052556/https://www.statnett.no/en/our-projects/interconnectors/nordlink/.
41. ENTSO-E, *Completing the map -Power system needs in 2030 and 2040.* Ten-Year Network Development Plan 2020, 2020: p. 66-67.
42. NordPoolSpot. *Maximum NTC August 18, 2020*. 2020; Available from: https://www.nordpoolgroup.com/4a3b58/globalassets/download-center/tso/max-ntc.pdf.
43. NordPool. *Historical Market Data*. n.d.; Available from: https://www.nordpoolgroup.com/historical-market-data/.
44. ENTSO-E Transparency Platform. n.d.; Available from: https://m-transparency.entsoe.eu.
45. NVE, *Langsiktig kraftmarkedsanalyse 2020 - 2040*. 2020: Oslo. p. 50.
46. Statistics Norway. *Production and consumption of energy, energy balance and energy account*. 2020; Available from: https://www.ssb.no/energi-og-industri/statistikker/energibalanse.
47. Norsk Fjernvarme. *fjernkontrollen*. Available from: https://www.fjernkontrollen.no/.

48. Danish Energy Agency and Energinet, *Technology Data - Energy storage: Large-scale hot water tanks* 2018: p. 53-59.
49. Statistics Norway, *Skogavvirkning for salg*. 2020.
50. Statistics Norway. *Produksjon og forbruk av energi, energibalanse ("Norwegian Energy Balance")*. 2020; Available from: https://www.ssb.no/energi-og-industri/statistikker/energibalanse.
51. NVE, *Bioenergi i Norge*. 2014.
52. Enova, *Mulighetsstudie - Bioenergi i Industrien*. 2012. p. 127.
53. Limits, C., *Ressursgrunnlaget for produksjon av biogass i Norge i 2030*. 2019.
54. IEA, *Global Hydrogen Review: Assumptions annex.* 2021.
55. Ulleberg, Ø. and R. Hancke, *Techno-economic calculations of small-scale hydrogen supply systems for zero emission transport in Norway.* International Journal of Hydrogen Energy, 2020. **45**(2): p. 1201-1211.
56. Reddi, K., et al., *Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen.* International Journal of Hydrogen Energy, 2017. **42**(34): p. 21855-21865.
57. Danebergs, J., *Techno-economic Study of Hydrogen as a Heavy-duty Truck Fuel: A Case Study on the Transport Corridor Oslo–Trondheim*. 2019, KTH: DiVA.
58. Elgowainy, A. and K. Reddi. *Hydrogen Refueling Analysis of Heavy-Duty Fuel Cell Vehicle Fleet*. 2017 DOE Hydrogen and Fuel Cells Program Annual Merit Review 2017 2019/04/19]; Available from: https://www.hydrogen.energy.gov/pdfs/review17/pd014_elgowainy_2017_o.pdf.
59. Norwegian Ministry of Finance, *Perspektivmeldingen. Proposition for Parliament, nr. 14 (2020-2021).* . 2020.
60. Lindberg, K.B., S.J. Bakker, and I. Sartori, *Modelling electric and heat load profiles of non-residential buildings for use in long-term aggregate load forecasts.* Utilities Policy, 2019. **58**: p. 63-88.
61. Karen Byskov Lindberg, *Impact of Zero Energy Buildings on the Power System. A study of load profiles, flexibility and system investments*. 2017, NTNU.
62. *Prosess 21 Hovedrapport*. 2021.
63. *Prosess21 Kraftmarkedet Ekspertgrupperapport*. 2020.
64. Miljødirektoratet, *Grønn omstilling: Klimatiltaksanalyse for petroleum, industri og energiforsyning*. 2022. p. 148.
65. Karen Byskov Lindberg, et al., *Flexbuild Annual Report 1 - Technical report with results analysis*. 2020, Sintef Community.
66. Standard Norge, *Energy performance of buildings — Calculation of energy needs and energy supply*. 2020.
67. Ericson, T., *Direct load control of residential water heaters.* Energy Policy, 2009. **37**(9): p. 3502-3512.
68. ENOVA, *Smart varmtvannsbereder.* 2022.
69. Hovi, I.B., et al., *User experiences from the early adopters of heavy-duty zero-emission vehicles in Norway: barriers and opportunities*. 2019.
70. Hovi, I.B., *E-mail: Kjørelengder og -bestand lastebiler og trekkvogner fra BIG*, Janis Danebergs and E. Rosenberg, Editors. 2021.
71. Samferdselsdepartementet, *Nasjonal transportplan 2022-2033*. 2021.
72. Miljødirektoratet. *Salget av avansert biodrivstoff økte i fjor*. 2019 2020/04/09/; Available from: https://www.miljodirektoratet.no/aktuelt/nyheter/2019/mai-2019/salget-av-avansert-biodrivstoff-okte-i-fjor.

73. Lovdata. *Forskrift om begrensning i bruk av helse- og miljøfarlige kjemikalier og andre produkter (produktforskriften)*. 2018; Available from: https://lovdata.no/dokument/SF/forskrift/2004-06-01-922/KAPITTEL_4#%C2%A73-3.
74. Winther, K. and J. Jeppesen, *Validering af energiforbrugsdata for køretøjer i AD modellen*. 2016, Teknologisk Institut.
75. Statistics Norway. *12577: Road traffic volumes, by type of vehicle and type of fuel*. 2019 2020/06/04/ 2019/07/28/]; Available from: https://www.ssb.no/en/statbank/table/12577/.
76. Figenbaum, E., et al., *360 graders analyse av potensialet for nullutslippskjøretøy*. 2019, TØI.
77. Islam, E., et al., *An Extensive Study on Sizing, Energy Consumption, and Cost of Advanced Vehicle Technologies*. 2018, Argonne National Lab.(ANL), Argonne, IL (United States).
78. Statistics Norway. *12575: Kjørelengder, etter kjøretøytype, alder, statistikkvariabel og år. Statistikkbanken*. 2019 2019/07/28/ 2019/07/28/]; Available from: https://www.ssb.no/statbank/table/12575/tableViewLayout1.
79. Fulton, L., et al., *Technology and Fuel Transition Scenarios to Low Greenhouse Gas Futures for Cars and Trucks in California*. 2019.
80. Hovi, I.B., *E-mail: ITEM - metodikk for å gjøre en korridoranalyse for tungtransport*, Janis Danebergs and A. Madslien, Editors. 2020.
81. Hagman, R. *Busser, Euro VI og avgassutslipp-Status 2016/2017*. [Online report] 2016; Available from: https://www.toi.no/publikasjoner/busser-euro-vi-og-avgassutslipp-status-2016-2017-article34177-8.html.
82. Statistics Norway. *Norwegian emissions to air*. [Internet] 2019; Available from: https://www.ssb.no/en/natur-og-miljo/statistikker/klimagassn/.
83. Hagman, R., et al. *Klima-og miljøvennlig transport frem mot 2025*. Vurderinger av Mulige Teknologiske Løsninger for Buss [Online report] 2017; Available from: https://www.toi.no/publikasjoner/klima-og-miljovennlig-transport-frem-mot-2025-vurderinger-av-mulige-teknologiske-losninger-for-buss-article34407-8.html.
84. Fridstrøm, L. and V. Østli, *Forsering eller hvileskjær? Om utsiktene til klimagasskutt i veitransporten*. 2021, Transportøkonomisk institutt: Oslo.
85. Skotland, C.H., E. Eggum, and D. Spilde, *Hva betyr elbiler for strømnettet.* NVE rapport, 2016(74-2016).
86. TØI, *Prosjekt: LIMCO*. 2021.
87. Kieldsen, A., et al. *Efficiency test method for electric vehicle chargers*. in *International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium*. 2016.
88. Thingvad, A., et al. *Assessing the energy content of system frequency and electric vehicle charging efficiency for ancillary service provision*. in *2017 52nd International Universities Power Engineering Conference (UPEC)*. 2017. IEEE.
89. Trentadue, G., et al., *Evaluation of Fast Charging Efficiency under Extreme Temperatures.* Energies, 2018. **11**(8): p. 1937.
90. Regjeringen, *Klimatiltak og virkemiddel i fiskeflåten.pdf*. 2019.
91. Fenstad, A. *Fiskeflåten har kuttet klimagassutslippene med to tredeler – fordi SSB endret regnemodellen*. 2019.
92. DNV-GL, *Reduksjon av klimagassutslipp fra innenriks skipstrafikk. Report 2019-0939 (in Norwegian)*. 2019.
93. DNV-GL, *Barometer for grønn omstilling av skipsfarten. Report 2019-0080 (in Norwegian)*. 2019.
94. Ocean Hyway Cluster. *Hydrogen infrastructure in the maritime industry*. 2020 2020/11/29/; Available from: https://www.oceanhywaycluster.no/projectlist/hyinfra.

95. Bjerkan, K.Y., et al., *Zero-emission passenger vessels for public tendered services. State of the art of technology and current use*. 2018.
96. LMG MARIN, CMR PROTOTECH, and NORSK ENERGI, *Potensialstudie - Energieffektiv og klimavennlig fergedrift*. 2015.
97. Shetelig, H., *Shipbuilding cost estimation: parametric approach*. 2013, Institutt for marin teknikk.
98. DNV-GL, *Analyse av tiltak for reduksjon av klimagassutslipp fra innenriks skipstrafikk. Report 2018-0181 (in Norwegian)*. 2018.
99. Rosenberg, E., et al., *Modelling the interaction between the energy system and road freight in Norway.* Transportation Research Part D: Transport and Environment, 2023. **114**: p. 103569.
100. Proost, J., *State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings.* International Journal of Hydrogen Energy, 2019. **44**(9): p. 4406-4413.
101. IEA, *The future of hydrogen. Seizing today's opportunities.* 2019.
102. Ulleberg, Ø., *Hydrogen Implementing Agreement - Task 33*. n.d., IEA Hydrogen.
103. Stolten, D., *Hydrogen and fuel cells: fundamentals, technologies and applications*. 2010: John Wiley & Sons.
104. Chardonnet, C., et al., *Early business cases for H2 in energy storage and more broadly power to H2 applications*. 2017, Tractebel and Hinicio: FCH-JU.

Appendix A – Basis for input values for electrolyzer

Hydrogen from electrolyzer is assumed to be produced in each region either centralized or distributed manner. The costs are provided both for alkaline and PEM electrolyzer and necessary compressor unit to compress it to 250 bar pressure.
The centralized unit is based on costs expected from a 20 MW_{el} installed capacity while costs for the decentralized unit are based on a 3 MW_{el} size electrolyzer.
The costs are composed from three parts: electrolyzer, compressor skid and other costs. The costs of electrolyzer is taken from [100] and represents costs for the electrolyzer and necessary auxiliaries such as:

- Transformer(s), rectifier(s), control panel with PLC;
- Water demineralizer/deionizer;
- Electrolyser stack(s);
- Gas analysers, separators and separating vessels;
- Scrubber or gas purifier system & recirculating pump;

An important distinction between PEM and Alkaline electrolyzers is the output pressure. The traditional Alkaline electrolyzers work usually at atmospheric pressure, while some electrolyzer designs provide self-pressurization up to 30 bar. On the other side PEM systems can self-pressurerize the hydrogen for up to 80 bar in commercial products. [101] In TIMES the cost of Alkaline electrolyzer is included a dry piston compressor which provides 15 bar output pressure, while the output pressure for PEM is assumed to be 55 bar.
The costs for compressor is based on a cost per installed kW capacity based on data from [102] and refined in [57]. The required compressor capacity to reach the set pressure is based on adiabatic compression defined as

$$W = \left[\frac{\gamma}{\gamma - 1}\right] * P_0 * V_0 * \left[\left(\frac{P}{P_0}\right)^{\frac{\gamma-1}{\gamma}} - 1\right]. \qquad \text{(A-1)}$$

Where P_0 is the initial pressure (Pa), V_0 is the initial specific volume (m^3/kg), P is the end pressure (Pa), and γ=1,41 is the adiabatic coefficient [103]. In addition, a mechanical efficiency of 70% is added and a compressor redundancy is set to 3 x 50%.

The other cost consists of [104]:

1. Engineering costs
2. Distributed Control System (DCS) and Energy Management Unit (EMU)
3. Interconnection, commissioning, and start-up costs

The other costs are expected to follow scale of economy; hence they are assumed to be 45% and 36% of CAPEX for 3 MW_{el} and 20 MW_{el} electrolyzer unit respectively.
Civil work costs are not included, which are here defined as construction of foundation, industrial buildings, lighting, water supply, fencing, security. Neither cost of land nor the option to extend the technical lifetime of the electrolyzer by only replacing the stack has been included in the model.
The development of costs is expected to decrease with time and are usually correlated with increased production volumes of the equipment. The reduction in price of electrolyzer is presented in [101] as a span between a max and minimum costs per kW_{el}. As current investment costs are based on a separate publication and are differentiated on size of the plant, only the trends of future costs are

used. In IFE-TIMES-Norway the cost development is based on the trend of the average costs. All the electrolyzer costs and expected reduction is shown in Table A-1.

Table A-1 Cost span of electrolyzers from [101] and price reduction for the average cost.

		Alkaline			PEM		
		Today	2030	Long-term	Today	2030	Long-term
Upper	USD_{2019}/kW_{el}	1400	850	700	1800	1500	900
Lower	USD_{2019}/kW_{el}	500	400	200	1100	650	200
Average	USD_{2019}/kW_{el}	950	625	450	1450	1075	550
Price reduction average price	-	0%	34%	53%	0%	26%	62%

The cost development of compressor is based on cost decrease factors presented in [56] where it is assumed that at production of 5 000 hydrogen refuelling stations (HRS) the hydrogen compressor could decrease with 53% and at production volume of 10 000 hydrogen refuelling stations (HRS) the decrease will be 60%. These production volumes are assumed to occur in 2030 and 2050 respectively and to represent also the reduction in compressor costs for middle and large-scale hydrogen production unit. It shall be noted that there are big technological differences between a compressor serving light-duty vehicle HRS (as referred to in the source) and large-scale hydrogen production unit, in addition prediction in future cost development is in general connected to large uncertainties.
In Table A-2 the cost used for each component (electrolyzer, compressor and other costs) are presented, while Table A-3 summarises the cost breakdown for the central compressor.

Table A-2 The cost for the different electrolyzers for different years shown in NOK per kW_{H2}. Compressor for decentralized production is added to the total electrolyzer cost.

			2018	2030	2050
20 MW el	PEM	Electrolyzer -	12769	8383	3985
		Other costs	4597	3018	1435
		Total costs	**17366**	**11401**	**5419**
	Alkaline	Electrolyzer -	8572	5515	3600
		Other costs -	3086	1985	1296
		Total costs	**11658**	**7500**	**4896**
3 MW el	PEM	Electrolyzer -	13585	8918	4239
		Compressor	2431	1142	972
		Other costs	7207	4527	2345
		Total costs	**23222**	**14588**	**7557**
	Alkaline	Electrolyzer -	10158	6535	4266
		Compressor	3474	1633	1389
		Other costs	6134	3676	2545
		Total costs	**19765**	**11843**	**8201**

Table A-3: The cost of centralized (large-scale) compression for different years shown in NOK per kW_{H2}

	2018	**2030**	**2050**
Compressor	2702	1270	1081
Other	973	457	389
Total costs	**3674**	**1727**	**1470**

The efficiency consists of two parts: i) the actual efficiency of the electrolyzer and ii) the electricity required to compress the hydrogen up to previously mentioned pressure and including the mechanical inefficiency. The values of efficiency for each part and the summarized value of efficiency used in IFE-TIMES-Norway is shown in Table A-4. An interval of efficiency of the electrolyzer is provided by [101] and in IFE-TIMES-Norway is used the middle value.

Table A-4 Efficiency of electrolyzer, compression stage and the summarized efficiency used in IFE-TIMES-Norway

		Alkaline			PEM		
		Today	2030	Long-term	Today	2030	Long-term
Efficiency of electrolyzer	Upper	70%	71%	80%	60%	68%	74%
	Lower	63%	65%	70%	56%	63%	67%
	Middle	67%	68%	75%	58%	66%	71%
Energy lost during compression as share of the energy in the compressed hydrogen	kWhel/ kWhH2	4.4%	4.4%	4.4%	1.9%	1.9%	1.9%
Summarized		65%	66%	73%	57%	65%	70%

The yearly OPEX costs for each component and a complete cost for the entire electrolyzer unit are shown in Table A-5.

Table A-5 Assumed OPEX costs

Equipment	Share of CAPEX
Electrolyzer	3%
H2 compressor	6%

An expected range of lifetime of the electrolyzer today and in future is presented in [101], the range and a middle value, which is used in IFE-TIMES-Norway, is shown in Table A-6.

Table A-6 Assumed lifetime of electrolyzer stack in hours, differentiated by electrolyzer type and time of production [101]

	Alkaline			PEM		
	Today	**2030**	**Long-term**	**Today**	**2030**	**Long-term**
Upper	90 000	100 000	150 000	90 000	90 000	150 000
Lower	60 000	90 000	100 000	30 000	60 000	100 000
Middle	75 000	95 000	125 000	60 000	75 000	125 000

Tittel: Documentation of IFE-TIMES-Norway v3

Dokumentklasse:

Signaturer:

Author:	Eva Rosenberg ife.no\Eva.Rosenberg	2023-03-14 12:28:51 (UTC+00:00)
Author:	Pernille Merethe Sire Seljom ife.no\Pernille.Seljom	2023-03-14 12:30:48 (UTC+00:00)
Author:	Kristina Haaskjold ife.no\kristina.haaskjold	2023-03-14 12:31:55 (UTC+00:00)
Review Approval:	Kari Aamodt Espegren ife.no\Kari.Espegren	2023-03-15 05:55:55 (UTC+00:00)
Content Approval:	Mari Lyseid Authen ife.no\mari.authen	2023-03-15 10:00:14 (UTC+00:00)

Kjeller
P.O. Box 40, NO-2027 Kjeller

Office address
Instituttveien 18, Kjeller, Norway

Tel.: +47 63 80 60 00

Halden
P.O. Box 173, NO-1751 Halden

Office address
Os allé 5, Halden, Norway

Office address, reactor facility
Tistedalsgata 20, Halden, Norway

Tel.: +47 69 21 22 00

firmapost@ife.no | www.ife.no | facebook.com/energiteknikk/ | @energiteknikk