Documentation of IFE-TIMES-Norway v1

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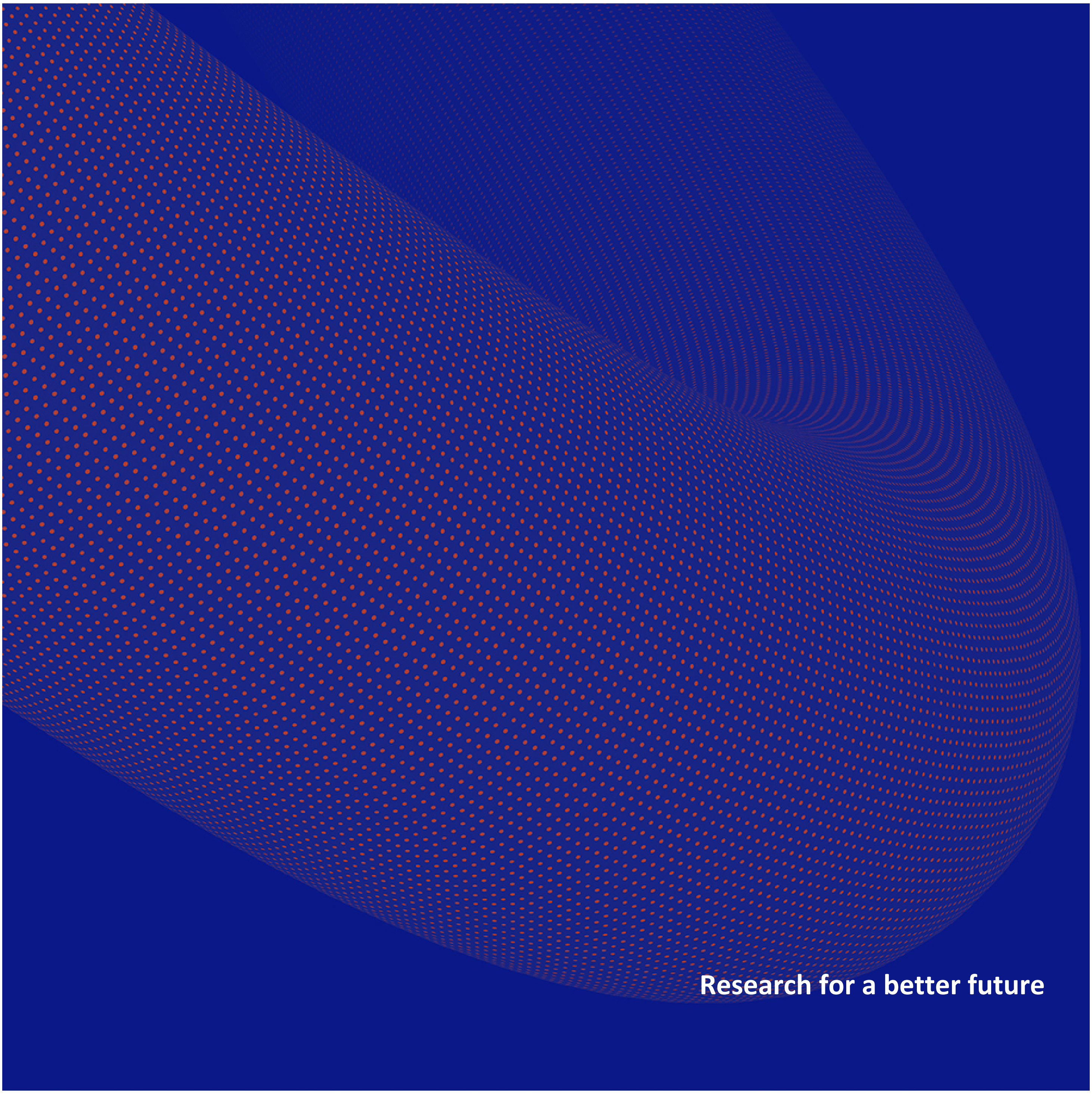

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Title:

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Summary:

The development of the energy system model IFE-TIMES-Norway started in 2017 in cooperation with Norwegian Water Resources and Energy Directorate (NVE). This report describes the model version 1 from September 2020. It is based on earlier versions of TIMES-Norway (2009) and MARKAL-Norway (1992). The model development is dynamic with continuously methodological developments and updates of input data.

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 Norway.

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.

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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 IFE-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 Norway [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; and technology characteristics such as costs, efficiencies, and lifetime and learning curves.

This report describes the status of IFE-TIMES-Norway by September 2020. 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. The focus of the recent model development in 2019 and 2020 has been on road transport, thus this part is more detailed described than other parts of the documentation. 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.

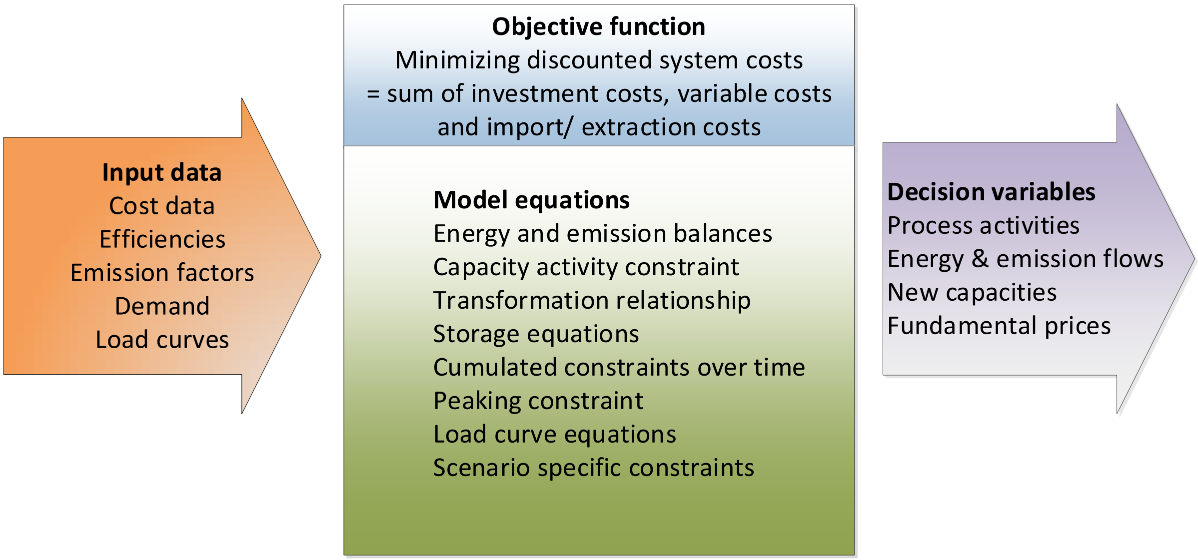


Figure 1 Schematic of TIMES inputs and outputs

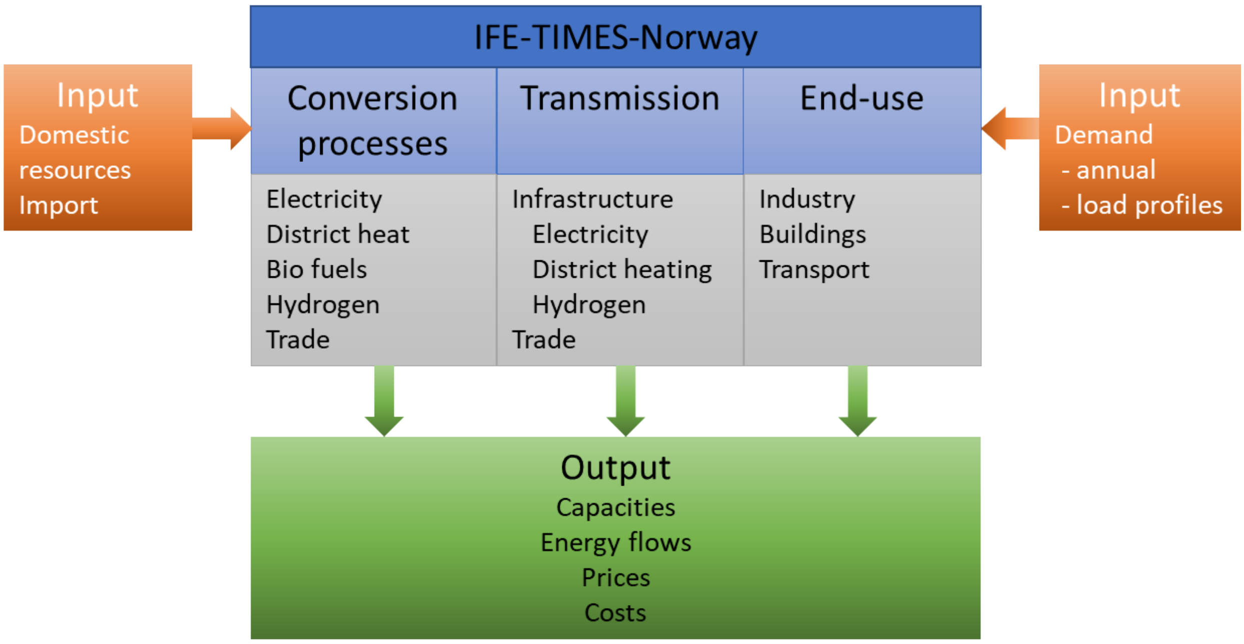


Figure 2 Schematic of IFE-TIMES-Norway

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 Figure 5 and 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
- 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: 5%
- Discount year: 2018
- Currency: kNOK2018
- Activity unit: GWh
- Capacity unit: MW
- Commodity unit: GWh

Figure 3: Regions included in IFE-TIMES-Norway, NO1 to NO5

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 is December – February. The total number of annual time slices is 4 * 24 = 96.

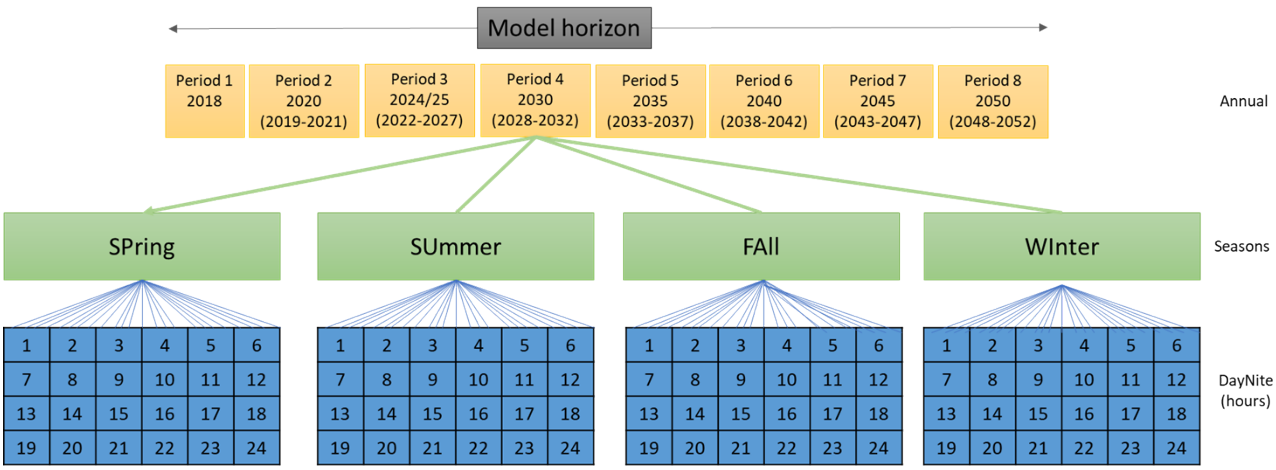


Figure 4 Time slice tree of IFE-TIMES-Norway (base version)

An overview of the different files included in IFE-TIMES-Norway is presented in Figure 5. The model consists of six basic files representing the end-use sectors buildings, industry and transportation and the energy sectors 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 file. 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 and solar capacity factors.

Assumptions often used in analyses are gathered in the scenario file "Base assumptions". This file includes electricity taxes, electricity trade prices and biomass balance.

Model files	*Content*
SysSettings	Starting year, time periods, time slices, discount rate, units etc.
Power, DistHeating	Production technologies Production potentials/restrictions
Trade	Trade links & parameters (existing and new)
Fuels	Fuels definitions, prices, potentials (biomass, waste, waste heat) Technology specific delivery costs Bioenergy production technologies CO2 emissions
Industry, Buildings, Transport	Annual demand Demand technologies incl. potentials/restrictions Hydrogen production technologies
Base_Profiles	TimeSlice profiles of demand & resources
Base_Assumptions	Norwegian biomass balance, electricity fee, electricity trade prices
SubRES_CCS	New technologies in different SubRES files
Scen_CO2_constraint Scen_CCS	Different scenario files

Figure 5 Overview of model files and main content

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 TIMES modelling framework can either be deterministic or stochastic, where the stochastic modelling approach can both consider short-term and long-term uncertainty [7]. 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. [8-11], 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, and the illustrated model results are based on a deterministic modelling approach.

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 those files. The modelling of hydrogen is further described in the next chapter.

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-PV-RES (electricity from solar power in residential building)
- ELC-PV-COM (electricity from solar power in commercial buildings)
- 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)

Electricity produced locally in residential buildings can only be used in the residential sector or sold to the low voltage grid. Similarly, electricity produced locally in non-residential buildings can only be used in the non-residential sector or sold to the low voltage grid.

The grid losses in the high voltage grid is assumed to be 3% and in the low voltage grid 7%. A grid fee is added to the low voltage grid. Based on the average grid fee for households in the period 2012-2019, 273 kr/MWh is used in the base case (constant in all project periods) [12].

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. The grid fees are included in the file "Base assumptions".

The district heating commodities are:

- LTH-DH-GRID (district heat from plant to grid)
- LTH-GRID-EX (district heat from grid to heat exchanger in end-use sector)

Commodities defined in the fuels file is presented in Table 1 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 and hydrogen. The prices in Table 1 presents the exogenous price to the model in those cases. Emissions is connected to the use of fuel commodities and included in the fuels file. The values used are presented in Table 2.

A general VAT of 25% is added to all costs in the residential sector. Investment costs in the residential sector is with VAT included. VAT of energy carriers is added as a flow delivery cost in the “Fuels-file” of fossil fuels, district heat and biomass. 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 “Base_Assumptions”. The fee is 0.5 øre/kWh in industry, 15.8 øre/kWh in commercial and 38.3 øre/kWh in residential (incl. VAT).

Table 1 Definitions of fuel commodities and prices

Output Commodity		Cost 2018 (NOK/MWh)	Cost 2030 (NOK/MWh)	Comments/references
BIO-COAL	Biocoal	1082	1082	assumption
BIO-FOR	Biomass-forest	139	139	SSB
BIO-FUEL	Biomass-based fuel in transport (based on biodiesel)	1372	1599	MDIR, without VAT
BIO-GAS	Bio gas	1149	1367	MDIR
BIO-LOG	Logs to wood industry			
BIO-MASS	Biomass - chips and pellets	70	70	assumption
BIO-WOOD	Biomass – wood	150	150	"selvhogst"
COAL	Coal and coal products (fossil)	87	90	NMBU
CSV	Energy conservation	0	0	
FOS	Fossil fuel in transport (based on diesel)	1043	1074	Diesel without VAT
GAS	Gas (based on LPG)	380	385	LPG price
H2	Hydrogen fuel in transport	1000	900	Assumption, blue hydrogen trade price
H2-IND	Hydrogen in industry			
OIL	Oil (based on light distillate)	705	705	Light fuel oil without VAT
SOL	Solar energy	0	0	
WASTE	Municipal waste	-273	-273	NVE
WASTE-HEAT	Waste heat from industrial processes	1	1	

Table 2 Emission factors (ton CO2/MWh)

	FOS	OIL	COAL	GAS	WASTE
Emissions, t CO2/MWh	0.266	0.266	0.239	0.24	0.173

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 3 summarizes the generation of existing and new hydropower plants.

Table 3 Hydro power 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	6.3
+ 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» [13]. The normal annual hydropower generation in 2019 is 141 TWh. It is based on mean production in 1981-2010 and with increased precipitation resulting in increased generation of 3.5 TWh today (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 [14].

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 [15]. In total, this results in 147 TWh hydropower production in 2040 by existing plants (including those under construction today).

The potential for new investments in hydropower is based on information from NVE in March 2018 and 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. The data for existing plants is based on the same literature as for the production capacities described over [13] and adjusted to the time slices of the model, since the NVE-data has another time resolution.

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 [16], where the capacity increased by 75% and the generation by 15%, resulting in an average availability of 65.7% of the original.

4.1.2 Wind power

Existing wind power plants are included with existing capacity and annual full load hours as presented in Table 4. The data are based on information from the wind power database of NVE [17]. 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 4 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 5300 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 are 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)

A wind power potential is calculated based on applications for wind power concessions downloaded from the database of NVE [19]. 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 48 TWh as shown by spot price region in Table 5. Note that the indicated wind power potential also includes existing wind power. The potential is equally divided in the 9 different wind power plant classes. The tenth class adds another 22 TWh of potential with the high cost and medium full load hours, in addition to plants included in the concession database.

Table 5 Wind power potential in a normal year, TWh/year.

	NO1	NO2	NO3	NO4	NO5	Norway
Consessions (class 1-9)	1.7	11.7	15.0	19.1	0.5	48
Additional potential (class 10)	0.6	4.7	5.3	11.1	0.2	22

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 PV

Photovoltaic electricity production is included as existing and new technologies in residential and non-residential buildings. No opportunity for investments in PV in industry or the power sector are included yet but is to be updated in newer model versions. The existing capacity is calculated until the end of 2020 and is 47 MW in the residential sector and 79 MW in the commercial sector [20].

The investment costs in base year are based on a marked survey conducted by Multiconsult in 2017 combined with estimates from IEA PVPS [21]. An overview of technology data of PV plants is presented in Table 6.

Table 6 Technology data of PV plants

	Investment cost		Operation and maintenance cost		Life time
	kr/kW		kr/kW		years
	2018	**2035**	**2018**	**2035**	
Residential	14 000	10 500	109	55	25
Commercial	10 000	7 000	145	75	25

PV production profiles is calculated based on profiles from renewables Ninja [22, 23]. 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 plants 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 residential PV-plants and 10°west/east for commercial plants.

A rough estimate of the maximum possible installation in buildings is calculated, see Table 7. In the residential sector, it is based on statistics on number of dwellings, assuming a capacity of 10 kWp per dwelling and assuming 20% of the dwellings not suitable (due to roof construction, shadowing etc.). In the commercial sector, statistics of existing non-residential buildings (excl. buildings in industry, storage and agriculture), assuming a capacity of 80 kWp per building and assuming 25% of the buildings not suitable (due to roof construction, shadowing etc.). This estimate is uncertain and should be updated.

Table 7 Region specific data of PV

	Annual share of full load hours		Potential (MW)	
	Residential	Commercial	Residential	Commercial
NO1	0.11	0.09	5 554	5 714
NO2	0.12	0.10	3 674	4 045
NO3	0.11	0.09	2 210	2 681
NO4	0.09	0.07	1 682	2 227
NO5	0.09	0.08	1 846	2 102
Norway			14 965	16 769

4.1.4 Transmission grid

The possibilities to invest and expand national transmission capacities between the regions are shown in Table 8, Table 9 and in Figure 6. The assumed investment cost of new capacity is also presented, where the investment cost varies due to the distance and technologies (cable vs. lines), based on project specific data [24-28]. New international transmission capacity to European countries are scenario specific and limited to maximum 1,400 MW. In the base template no new investments in international transmission is allowed.

Table 8: 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 9 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			

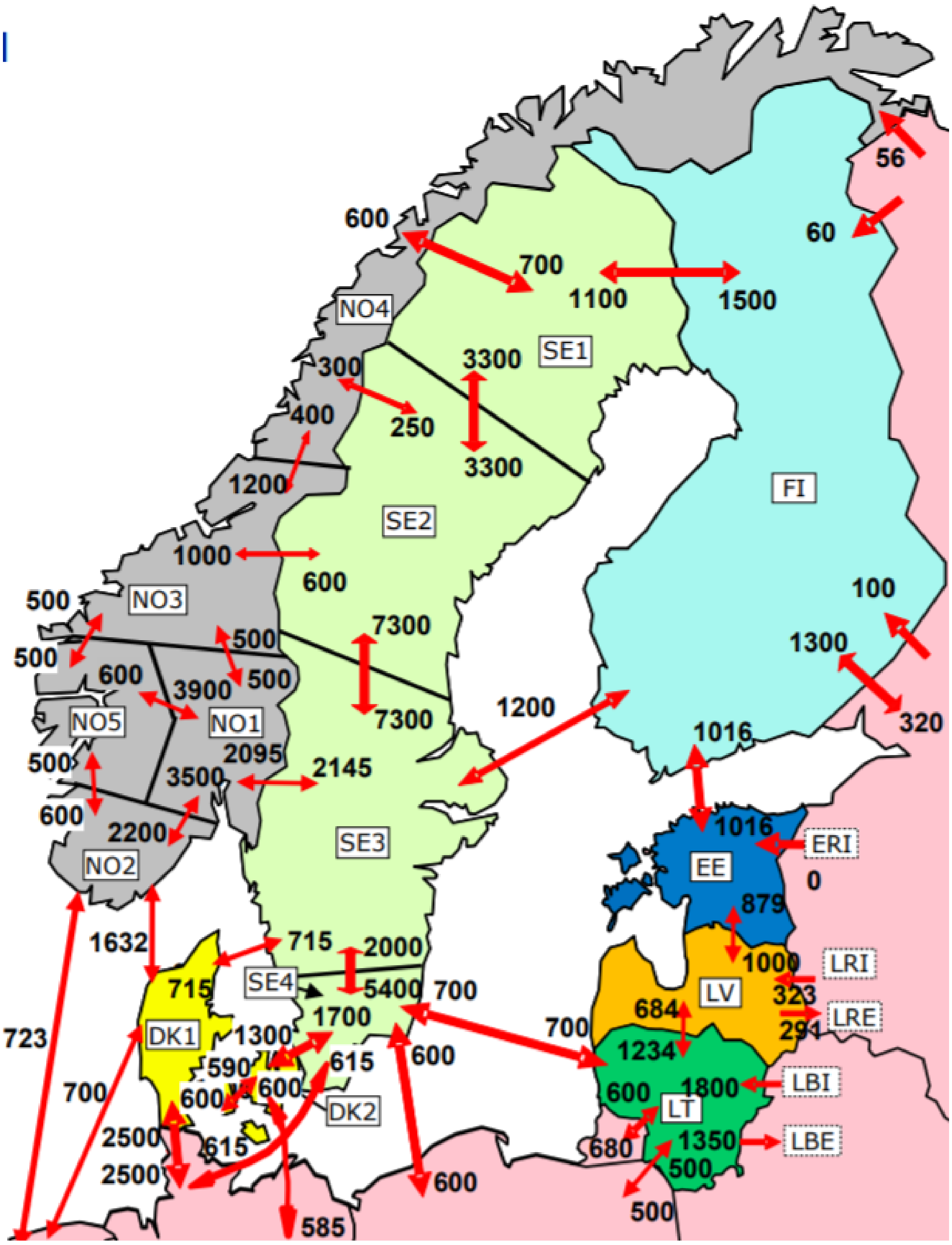


Figure 6 Net transmission capacities between regions, MW [29]

4.1.5 Electricity trade

IFE-TIMES-Norway need 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 [30] and entso-e [31]. The future prices are a result from the EMPIRE model (a long-term European electricity market model) where it is decided that CCS is an available technology [32]. Figure 7 shows an example of the prices for export to Germany, where the blue line is historical prices used in the base year and the red line is prices for 2050. The prices are to increase with an average of 48 %. Table 10 gives the percentage electricity price increase for all lines connecting Norway to other countries. It is assumed a linear interpolation of the prices between the two given years.

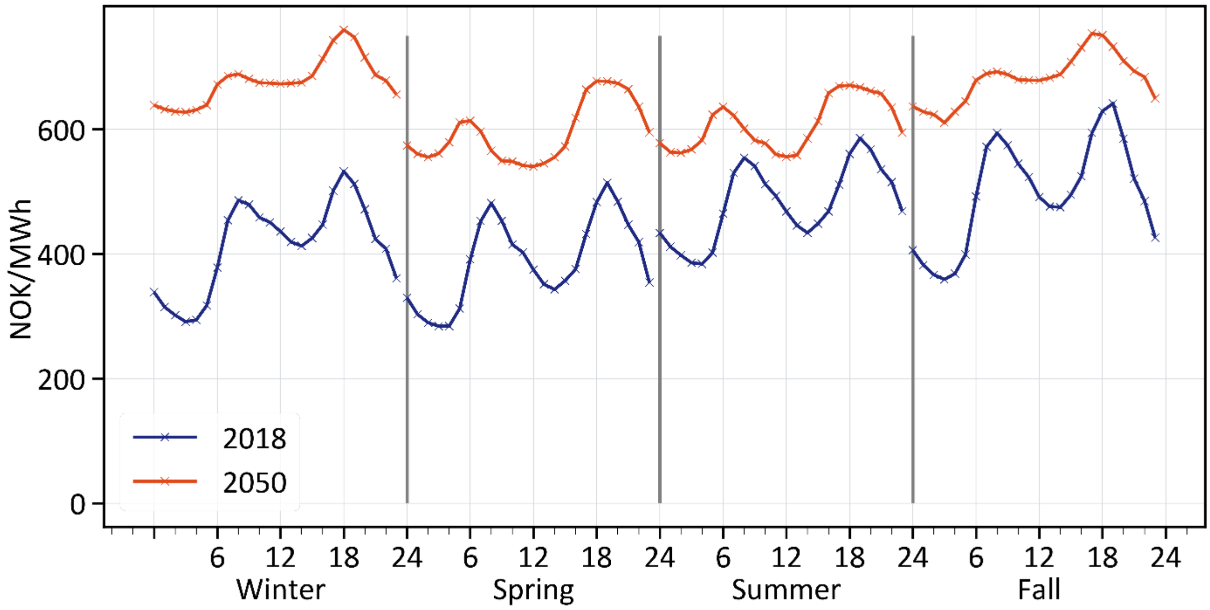


Figure 7 Electricity prices for export to Germany in base year and in 2050.

Table 10 Avg. percentage increase of electricity prices from 2018 to 2050.

To/from region	Avg. percentage increase 2018-2050
NO1 – SE3	32 %
NO3 – SE2	32 %
NO4 – SE2	32 %
NO4 – SE1	32 %
NO4 – RUS	46 %
NO2 – DK1	44 %
NO2 – DE	48 %
NO2 – NL	24 %
NO2 – UK	5 %
NO5 – UK	5 %

4.2 District heating

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 possibilities for new investments in district heating boilers and CHP with used data is presented in Table 11. Cost reductions due to technology learning is based on [18].

Table 11 District heating plants

Technology	Existing stock (MW)	Investment cost 2018 (kr/kW)	Technology learning	Efficiency	Life time (years)
Fossil boiler	180				5
Waste boiler	362	35 602	4%	88%	20
Biomass boiler	459	7 525	2%	83%	15
Electric boiler	383	1 297	0%	98%	20
Heat pump	144	13 776	20%	2.8	20
Heat recovery	25				50
CHP	82	29 247	4%		20

A maximum market share of 20% is used for heat pumps in district heating plants.

The losses of the district heating grid are differentiated per season to the following efficiencies; Winter 91%, spring and fall 88% and summer 85%.

Municipal waste can only be used in district heating plants and it is assumed that the volumes of today will be constant until 2050. It could be argued both for an increase due to increased population and a decrease due to more recycling of materials and less use of resources. The municipal waste has to be used, since it is not allowed to deposit waste anymore.

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 used of waste incineration plants and avoid double counting of stock.

All technology data is added to the capture process, since separate data of capture and transport/storage are not available. Technology data [33] is based on the reports «Kvalitetssikring (KS1) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2» from 2016 and «Kvalitetssikring (KS2) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2 Rapport fase 1 og 2» from 2018 [34, 35]. The following data are used:

- Captured CO2 295 kt per year and from 2030 332 kt CO2 per year
- Efficiency 77% and from 2030 87%

- Investment costs 9700 mill. NOK increased by 30% in the KS2-report to 12610 mill NOK, resulting in specific costs of 32059 kNOK/kt CO2
- Operating costs 349 mill NOK per year resulting in specific costs of 1319 kNOK/kt CO2

The starting year in NO1 is assumed to be 2025 and in the other regions 2030. The investment costs are different in different regions and year, but this differentiation is not based on literature, it is only an assumption to facilitate incorporation of site-specific data in the future.

Heat and electricity consumption are added to the capture process based on the same source as above [36] and also here is the operating cost used in the model is halved.

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 based on the use of today is included. 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 8. 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 [33] and presented in Table 12.

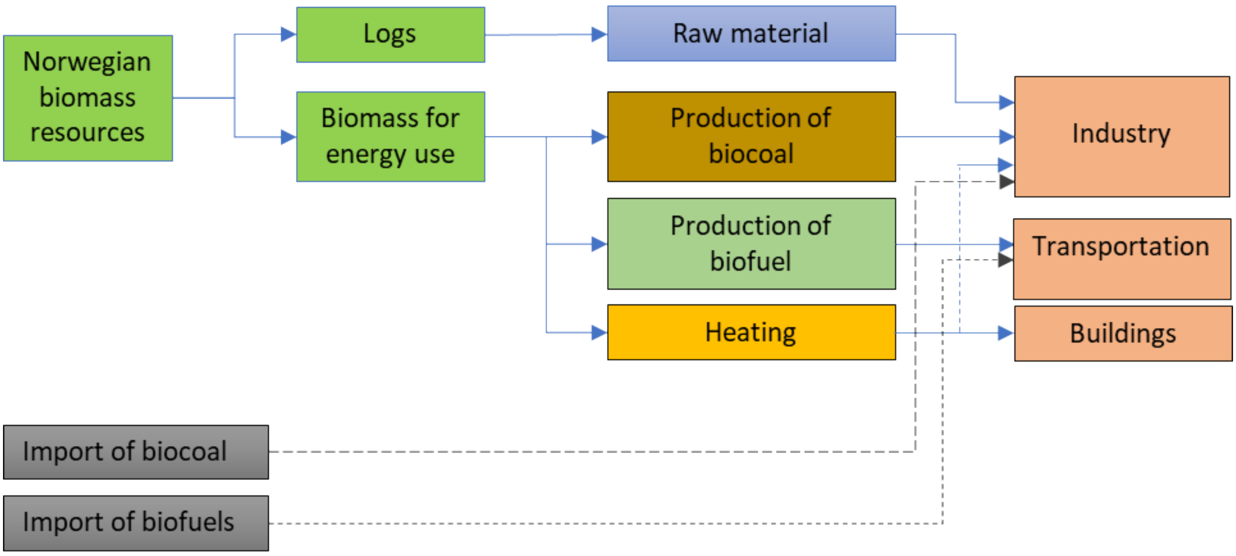


Figure 8 Schematic overview of biomass resources, conversion processes and end-use

Table 12 Technology data for conversion of biomass to biofuel or bio coal

	Efficiency	Life time (years)	Investment cost (NOK/MW)	Fixed O&M cost (NOK/MW)	Variable O&M cost (NOK/GWh)
Biofuel	58%	30	23 791	2469	200
Bio coal	25%	30	10 000		41

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 9. 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 [37], 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).

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 [38]. A total of 7 TWh was exported and 1 TWh was imported [37]. Industrial use of charcoal was approx. 0.5 TWh. In total, the current consumption of 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 about 3 TWh. A realistic potential is estimated at about 2 TWh and a theoretical one at about 4 TWh in [39]. In [40] 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 [33].

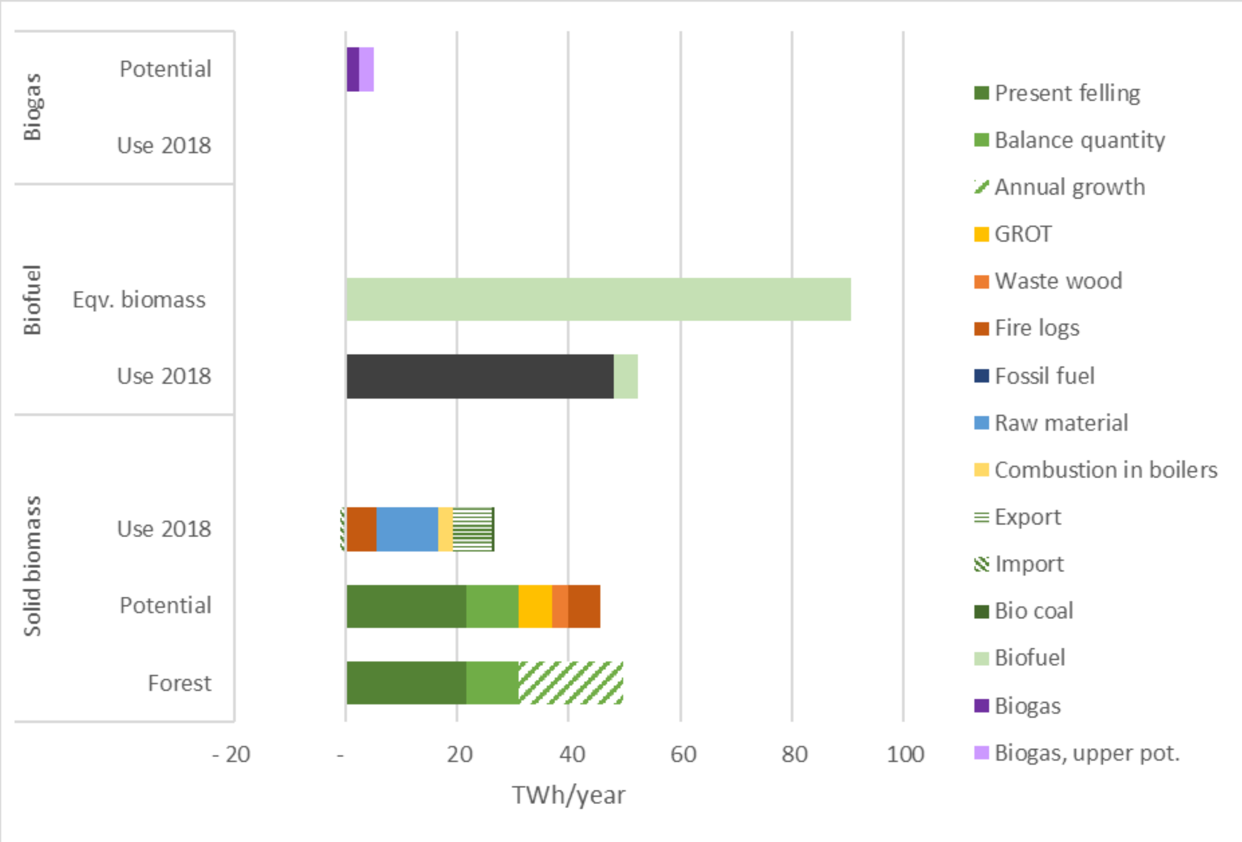


Figure 9 Biomass potentials and use, TWh/year

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. A limitation of biogas is also added, 0.4 TWh in 2018-2020 increasing to 3 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 2030, no import of biofuels or biocoal is possible, and before 2030 there is no limitations.

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 are included the technologies which are considered relevant for Norway and are illustrated in Figure 10. The commodity H2-cent is assumed to be compressed hydrogen at 250 bars. In commodities H2-road and H2-maritime the hydrogen is still compressed, and in addition both distributed and handled by filling infrastructure, which might increase the pressure further.

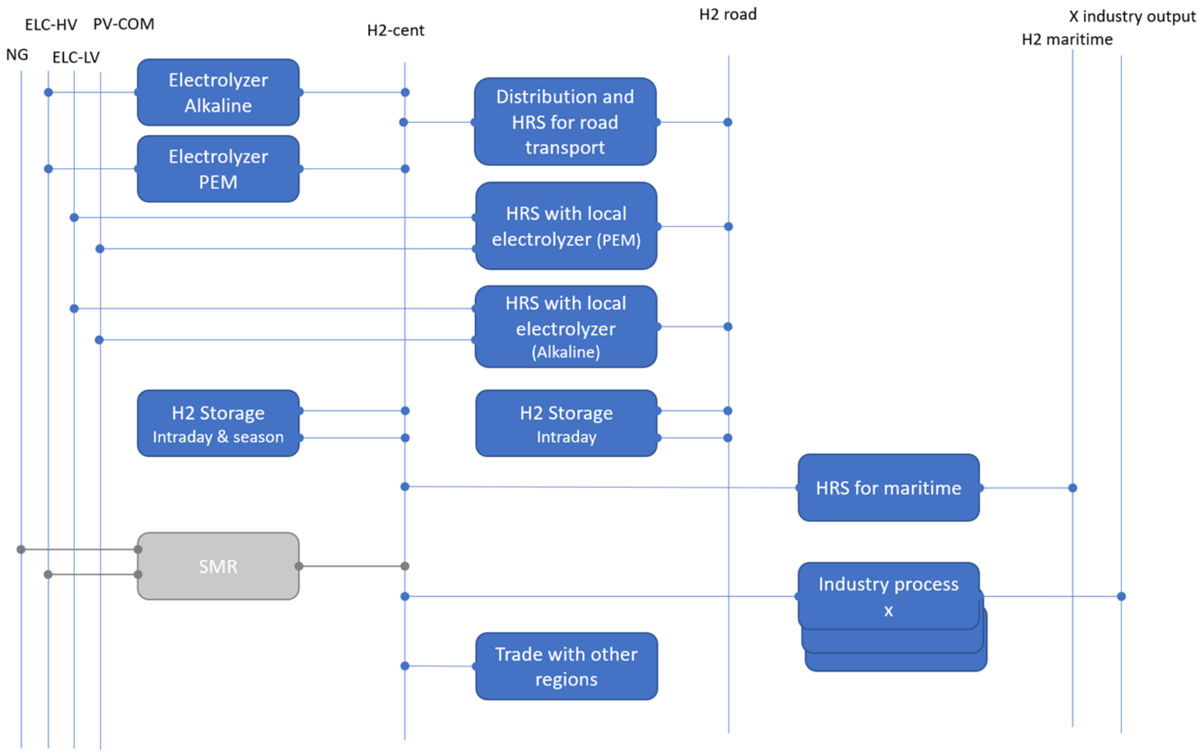


Figure 10 RES of hydrogen system presented in IFE-TIMES-Norway. The grey box shows technology not yet added to the model.

In the present version of the model, hydrogen is produced with electrolyzer and in further work the intention is to include production by steam reforming of natural gas (SMR) with CCS.

4.4.1 With electrolyzer

Hydrogen from electrolyzer is assumed to be produced in each region either large scale (centralized) or small scale (distributed) and cost wise are represented by a 10 MW_{el} and 1 MW_{el} installed capacity, respectively. The costs are provided both for alkaline and PEM electrolyzer and are build up from three parts: electrolyzer, compressor skid and other costs. The other costs cover engineering, control systems, interconnection, commissioning, and start-up costs. In Table 13 are shown the aggregated investment costs, while in Table 14 used efficiency and lifetime of the electrolyzers are presented.

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

Table 13 The cost for the different electrolyzers for different years shown in NOK per installed kW_{el}

		2018	2030	2050
10 MW el	PEM	11511	8192	4349
	Alkaline	11375	6857	5173
1 MW el	PEM	24770	17026	9413
	Alkaline	21905	13229	9972

Table 14 Efficiency of electrolyzer and compression stage

	Alkaline			PEM		
Efficiency (%)	65%	66%	73%	57%	65%	70%
Lifetime (h)	75 000	95 000	125 000	60 000	75 000	125 000

The yearly OPEX costs are built up for a differentiated value between electrolyzer types and a separate value for the compressor. The sum of OPEX as a share of CAPEX is shown in Table 15. The increase in share of CAPEX with size is correlated to the decrease of other or non-equipment costs for large share electrolyzers.

Table 15 Assumed OPEX costs

		Share of CAPEX
10 MW el	PEM	4%
	Alkaline	3.3%
1 MW el	PEM	4%
	Alkaline	3.4%

The large-scale and distributed electrolyzers are in addition to CAPEX and OPEX distinguished by electricity source; where large-scale electrolyzer is assumed to consume power from the high-voltage grid and the distributed electrolyzers are dependent on the low-voltage distribution grid for which are included grid tariff on top off the electricity cost. On the other side, for the distributed electrolyzers it is also added an option to use power from PV production from panels installed at commercial buildings.

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

4.4.2 Storage

The storage of hydrogen is assumed to be at 250 bars. Cost for such storage is taken from [41] and is 6300 NOK/kg.

Storage within a day is available both for hydrogen commodity at large scale production (H2-CENT) and for local hydrogen production for transport (H2-TRA). On the other hand, seasonal storage is only enabled in connection to large scale production units.

4.4.3 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 16. In [4] 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 [7] 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 start year.

Table 16 Cost for HRS from different sources

		Light-duty vehicles	Heavy-duty vehicles	
		[42]	[43]	[44]
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 [7] 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.

4.4.4 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 due to hydrogen having to be liquefied or building H2 pipelines.

Therefore, trade in hydrogen has only been added for adjacent geographical areas within Norway and the costs for it is based on the distance between the main cities within each region. The distance between regions and costs of transport is shown in Table 17. 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 17 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
		NO3	Trondheim	490	23
		NO5	Bergen	460	22
NO2	Kristiansand	NO1	Oslo	320	15
		NO5	Bergen	470	22
NO3	Trondheim	NO1	Oslo	490	23
		NO4	Tromsø	1100	49
		NO5	Bergen	700	32
NO4	Tromsø	NO3	Trondheim	1100	49
NO5	Bergen	NO1	Oslo	320	15
		NO2	Kristiansand	470	22
		NO3	Trondheim	700	32

The hydrogen used in the transport sector can either be produced in large scale and distributed or be produced locally, as illustrated in Figure 10. The costs of distribution of hydrogen within a region will be affected by its size. The distance and connected costs of distribution are developed using a simple methodology based on the distance between regions showed in Table 17. 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 is 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 11. In the second step is assumed that regions have approximately 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 11. The average distance between regions, the short and long distance of distribution and costs for distribution in IFE-TIMES-Norway is presented in Table 18 and are based on a 40-foot tube trailer that distributes 500 kg per day.

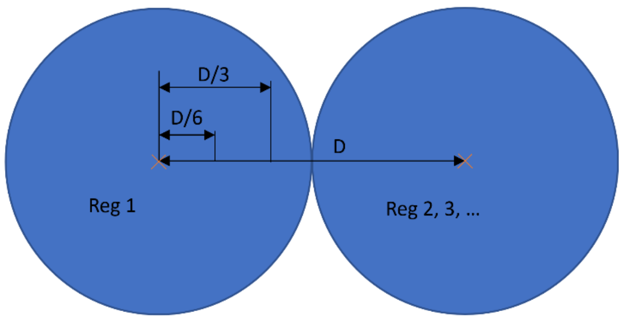


Figure 11 Illustration of how distance of distribution within regions are developed.

Table 18 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 - 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)
- Data - Data centres
- AGR&CON - Agriculture and construction

Each sub-sector has a demand of heat, electricity (for non-heating purposes) and/or raw materials. The demand is defined by the energy balance of 2018 and the projection is based on known development the next coming years and mainly an assumption of constant energy demand after that, see Figure 12 and Figure 13. Some increased demand of new activities such as data centres is included in the demand projections.

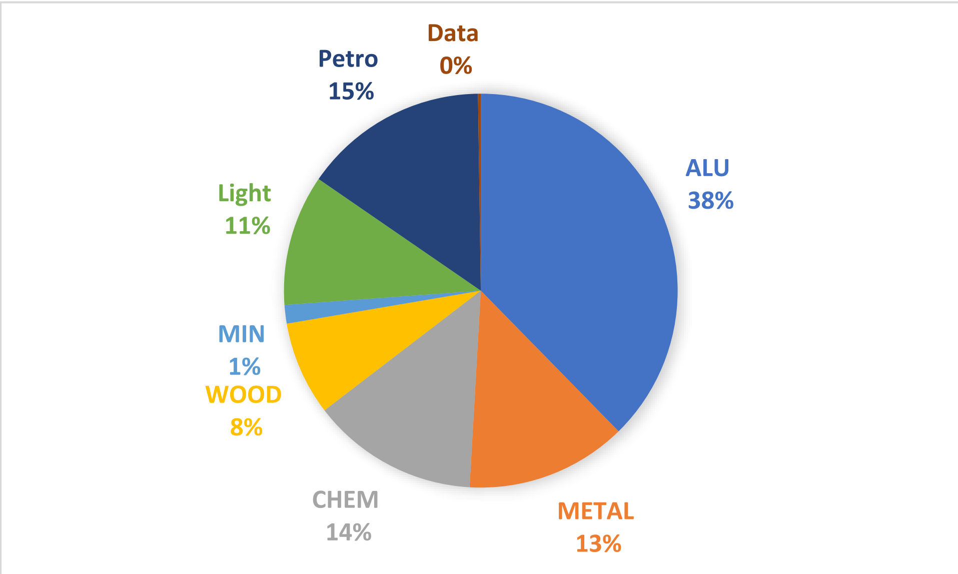


Figure 12 Share of electricity for non-heating purposes by sub-sector of total use in industry in 2018, TWh/year

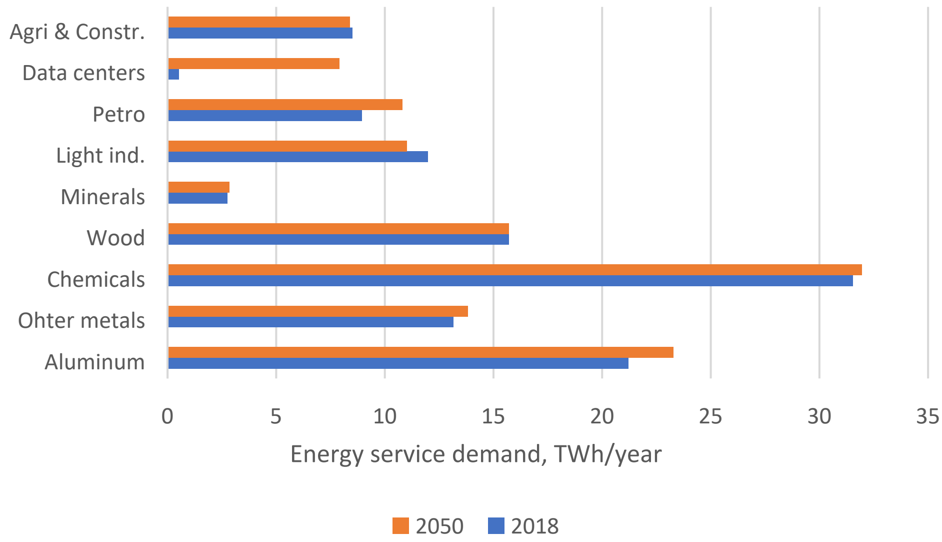


Figure 13 Total energy service demand in 2018 and 2050, TWh/year

The load profile of all industry sub-sectors but light industry is assumed to be flat, i.e. continuous operating time all year. In light industry, a daily load profile is added, see Figure 14, assuming no seasonal variation. It is set to be equal to the profile of commercial buildings [45, 46].

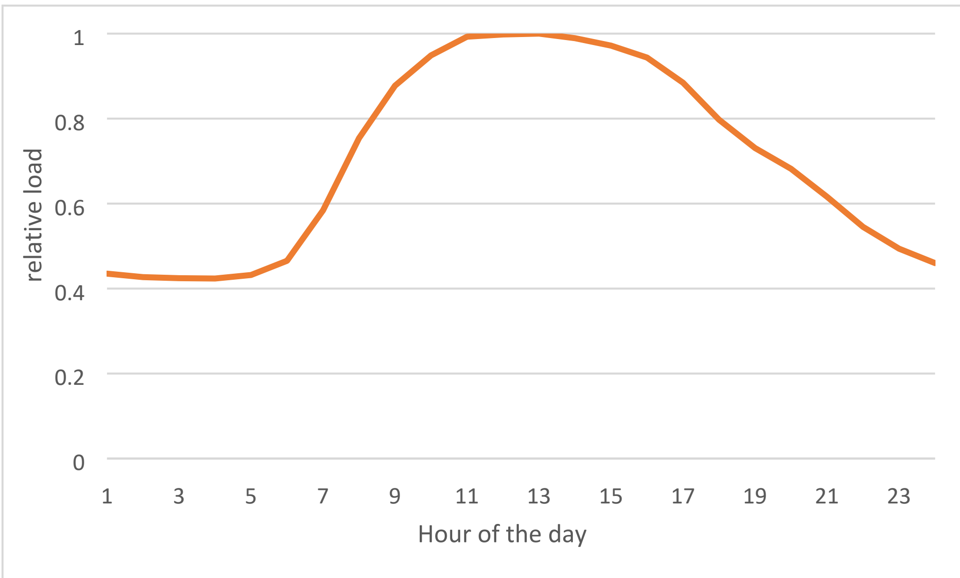


Figure 14 Load profile per day in light industry

5.1.2 Demand technologies

The electricity for non-heating purposes is modelled as one technology using ELC-HV in all industry sub-sectors except light industry, agriculture and construction that are 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 of energy carriers. In 2018 the share is fixed in accordance with the energy balance and in 2040 an upper limit is applied.

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). In the base case, this possibility is restricted to Yara in NO2 and use in a few reduction processes.

5.1.3 CCS

CCS in cement production is included as a possibility in SubRES files: SubRES_CCS and SubRES_CCS_Trans, with region specific data in the Trans-file.

The technology data for the CCS processes are based on the case studies of Breivik and Klemetsrud and all technology data are included in the CAP-processes. This could later be divided by costs and efficiencies at the plant and for transportation and storage. Storage might also be one process for Norway, with trade between the regions, but this is not implemented.

Technology data are based on the reports «Kvalitetssikring (KS1) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2» from 2016 and «Kvalitetssikring (KS2) av KVU om demonstrasjon av fullskala fangst, transport og lagring av CO2 Rapport fase 1 og 2» from 2018 [34, 35]. The middle alternative of Norcem Breivik is used and the data are:

- Captured CO2 400 kt per year
- Efficiency 85%
- Investment costs 9500 mill. NOK increased by 20% in the KS2-report to 11400 mill NOK, resulting in specific costs of 21 375 kNOK/kt CO2
- Operating costs 349 mill NOK per year resulting in specific costs of 873 kNOK/kt CO2

All technology data is added to the capture process, since the reports do not differ between costs for capture and costs for transport/storage, but this can easily be changed, if data are available.

Electricity consumption is added to the capture process, based on information from [36]. Since the operating cost of the KS-reports includes energy use, the operating cost in the model is halved, but this cost needs to be further checked.

5.2 Buildings

5.2.1 Structure

The building sector is divided in residential and non-residential/commercial buildings. All buildings are divided in existing and new buildings. The existing buildings have a stock of equipment in the start year. In the residential buildings, end-use demand is divided in central heating (HC), point source heating (H), hot water (W) and electricity specific demand (E). In the commercial buildings, end-use demand is divided in central heating (HC), point source heating (H), cooling (C) and electricity specific demand (E). A schematic overview of the systems in residential and commercial buildings is presented in Figure 15 and Figure 16. Oil boiler is only available in before 2020. Solar collectors are added as a possible technology with start year 2100.

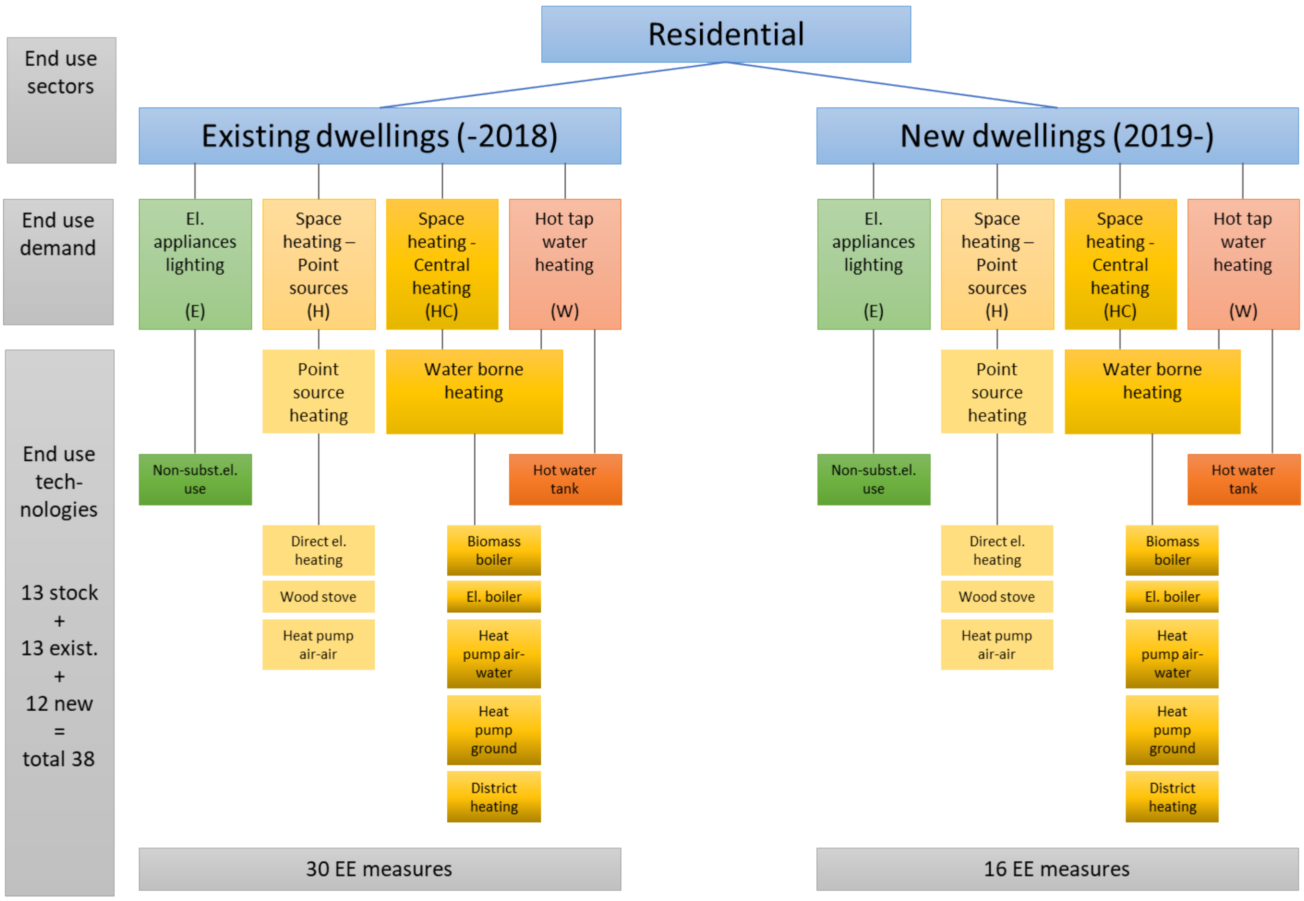


Figure 15 Schematic overview of the energy system in residential sector

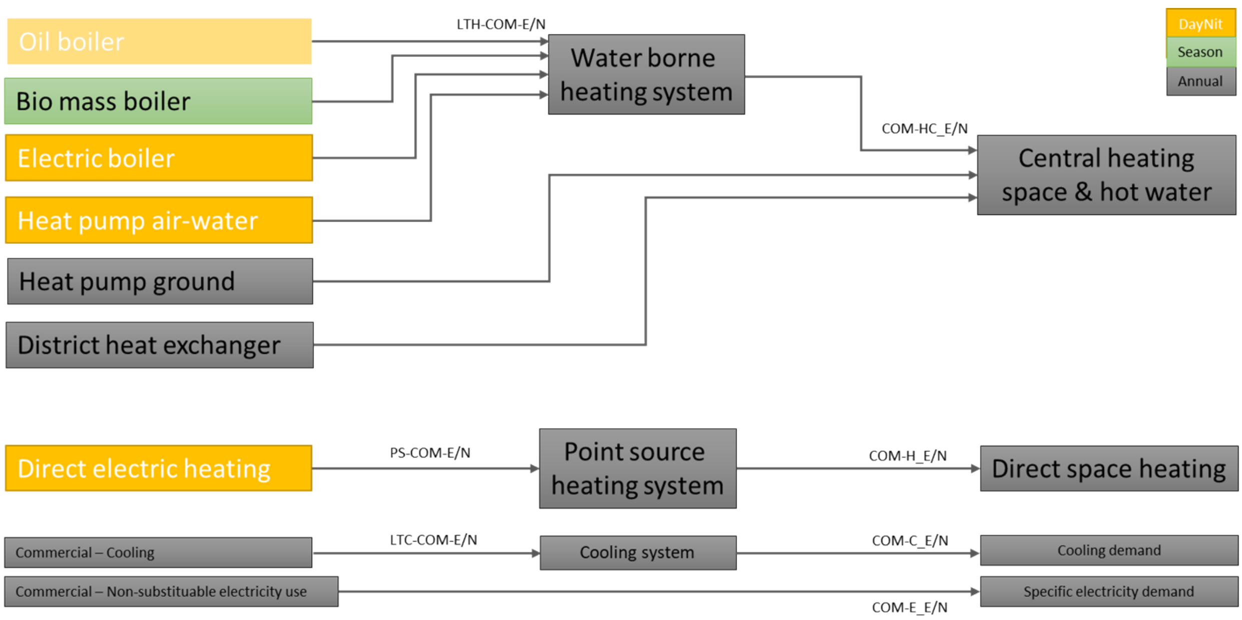


Figure 16 Schematic overview of the energy system in commercial buildings

In the residential sector, heating is divided in central heating (water borne system) and “point source” heating based on data for NVEs LEAP-model [47]. Based on these data, 12% of energy use in 2018 is central heating. Another possible source is statistics of heating equipment in 2012, which was the latest available data from SSB, and based on these data 18% was central heating. In commercial buildings, the share of central heating is 10% in 2018, based on data from LEAP. If this share should be changed, the stock of heating technologies must be updated as well.

Of the households in 2012, 18% had a boiler, district heat or “other” heat pumps (not air to air). “Other” heat pumps probably consist of both air and water borne systems and all of it should therefore probably not be included in water borne systems. If all other heat pumps are excluded, the share of central heating is 14%. Information from NVE on installed capacities of heat pumps gives only a small share of heat pumps connected to ventilation and it is therefore considered as a good approximation to assume that all other heat pumps are connected to central heating (water borne system). For new dwellings it is assumed a share of 60% central heating.

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).

5.2.2 Demand projections and load profiles

The demand projections in residential and non-residential buildings is based on data from previous work in FME CenSES, see Figure 17 [48]. It is based on the population projection from SSB in 2016. The demand in households is based on population in each area in the projections up to 2040, and after 2040 the share of each region is kept constant. The commercial buildings use the base year figures from FME CenSES and the projection is based on the relative population growth.

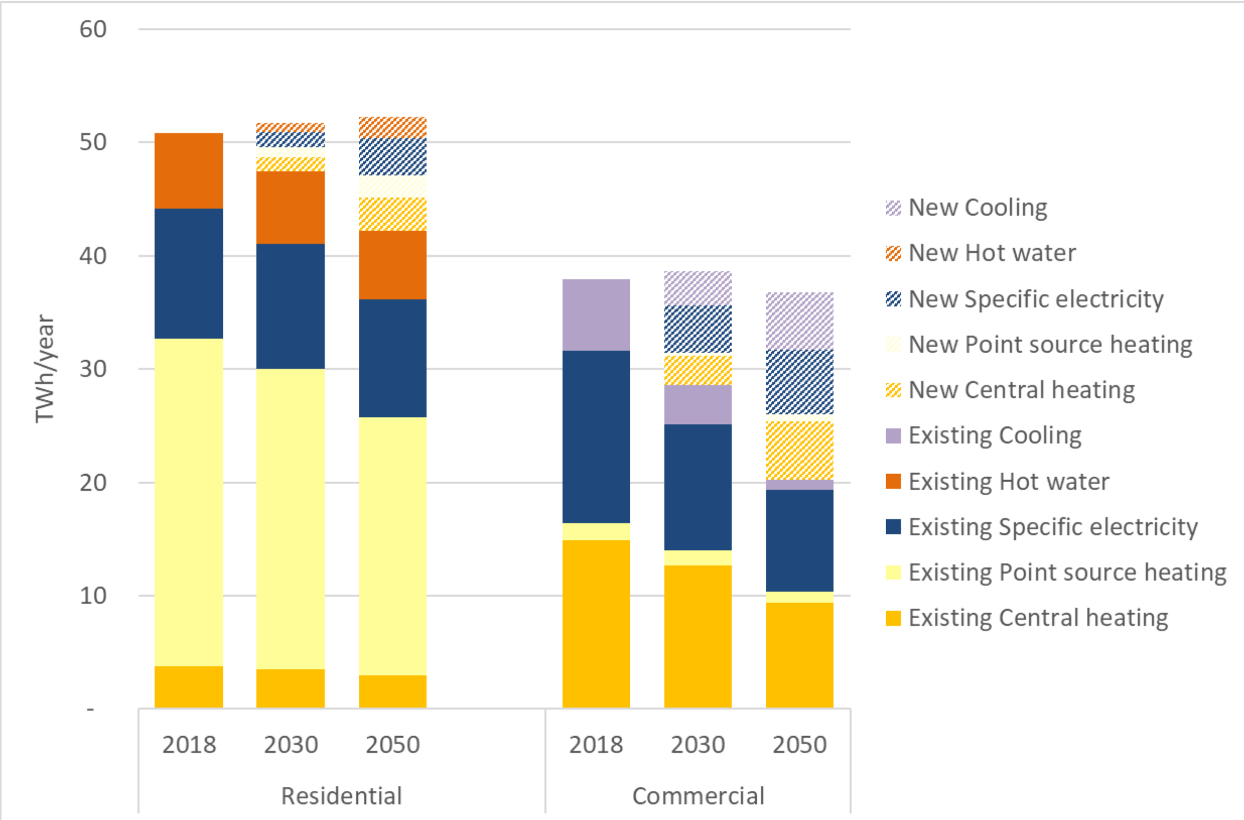


Figure 17 Projections of energy service demand in residential and commercial buildings, 2018, 2030 and 2050, TWh/year

The load profiles, the sub-annual hourly load variations, are based on input from [45, 46]. 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 18 and Figure 19.

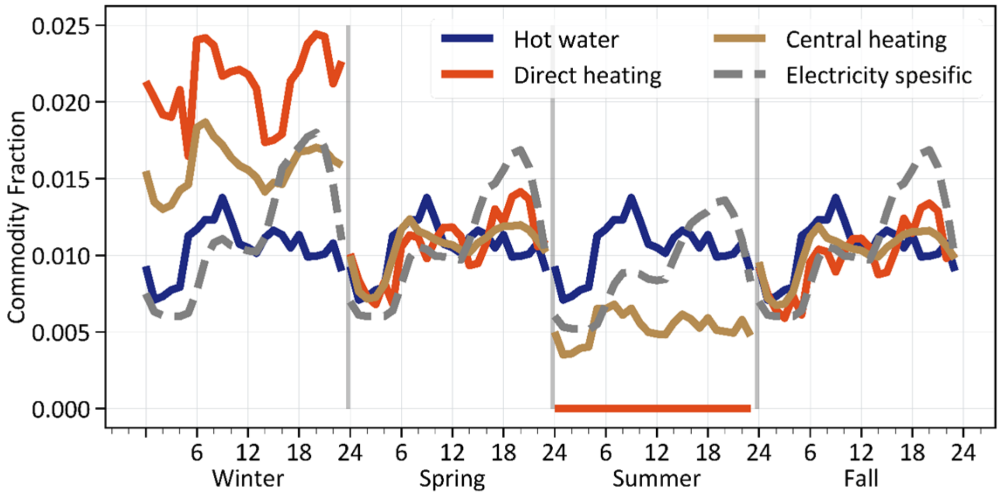


Figure 18 Load profile for residential buildings in model region NO1.

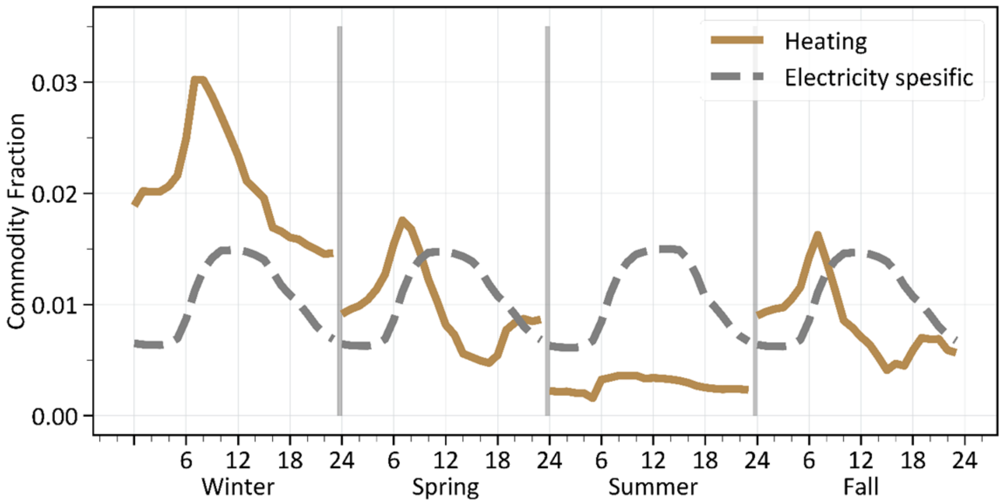


Figure 19: Load profile for commercial buildings in model region NO1.

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 19. Equipment in the residential sector includes VAT 25%.

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 LEAP-data of energy use in 2018 and full load hours from [18].

The efficiency of air-air heat pumps and air-water heat pumps depends on the season, see Table 20.

Table 19 Technology data of heating equipment in buildings

Description	Efficiency /COP	Utilization Factor	Market Share	LIFE	INVCOST	INVCOST 2035	FIXOM	VAROM
		Existing/New	Existing/New	years	NOK/ kW	NOK/kW	NOK/ kW	NOK/ MWh
Residential								
Central heating								
Biomass boiler	0.81	0.32		15	12 876	12 618	938	0.91
Electric boiler	0.98	0.29		20	4 046	4 046	540	0.13
Solar collector	1.00	0.07	0.10	25	10 715	7 501	54	
District heat exchanger	0.99	0.31	0.10	50	4 375	4 375	-	-
Heat pump water-water		0.2/0.37	0.26/0.30	20	20 523	16 418	50	1.88
Heat pump air-water		0.22/0.2	0.54/0.62	15	17 966	14 373	50	1.88
Point sources								
Heat pump air-air		0.22	0.27/0.34	15	6 872	5 498	38	
Wood stove	0.4			25	3 002	3 002	45	
Direct electric heating	1.00	0.29		25	2 042	2 042	31	1.25
Electric water heater	0.98	0.11		20	4 500	4 500		
Non-Residential								
Central heating								
Biomass boiler	0.84	0.32		15	7 897	7 739	520	0.73
Electric boiler	0.98	0.29		20	1 546	1 546	32	0.11
Solar collector	1.00	0.07	0.1/0.05	25	5 714	4 000	29	
District heat exchanger	0.99	0.35	0.3/0.7	50	918	918		
Heat pump water-water		0.37	0.56/0.63	20	15 643	12 514	40	1.50
Heat pump air-water		0.37	0.52/0.60	15	6 790	5 432	40	1.50
Point sources								
Direct electric heating	1.00	0.29		25	1 226	981	18	1.00
Chiller	4.00	1.00		25	3 000	3 000	60	8.00

Table 20 Seasonal efficiencies of heat pumps

	Fall	Spring	Summer	Winter
Residential, Air-air	2.5	2.5	2.5	1.5
Residential, Air-water	2.5	2.5	2.5	1.5
Commercial, Air-water	3.0	3.0	3.0	1.5

A maximum market share is added for heat pumps (see Table 21) and district heating. The maximum share of district heating in dwellings is as a starting point assumed to be 10%, in existing non-residential buildings 60% and in new residential buildings 70%.

NVE has estimated coverage and prevalence for three types of heat pumps in three types of buildings, see Table 21.

Table 21 Market share of heat pumps and district heating

	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 20. 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.

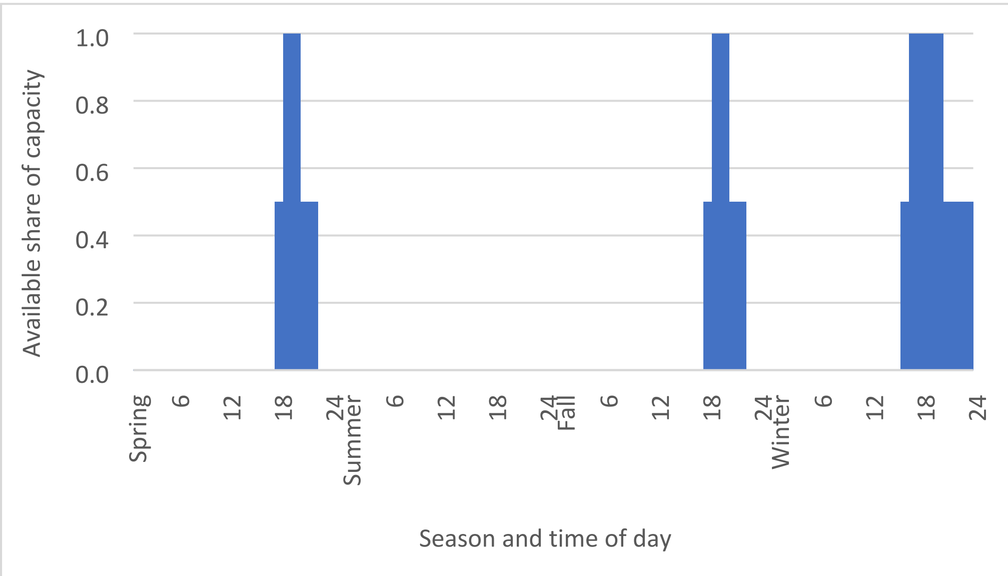


Figure 20 Illustration of available share of capacity for wood stoves per season and time of day (hour).

5.2.3.2 Energy efficiency measures

It is important to avoid double counting of energy efficiency measures. Our methodology is based on the following principles:

1. Regulations and laws are included in the energy service demand projection (e.g. buildings regulations, directives on equipment such as lighting bulbs, energy labelling)
2. More energy efficient energy production equipment is modelled as different technology options (heat pumps, more efficient boilers, solar heating and solar photovoltaic) as well as more efficient vehicles
3. Other types of energy efficiency measures are modelled as different technologies but not available in the base case (e.g. energy management, control and regulation, insulation, information, ventilation)

The energy efficiency measures have investments cost, lifetime and an upper potential. In the base case, the start year is 2100 and the technologies are included in scenarios with starting year e.g. 2025. The costs and potential of different energy efficiency measures are based on work done in FME CenSES in 2014. This work was based on different available studies, such as [49-52]. The values have a high degree of uncertainty and should be updated. The potential in 2025 is calculated to 16 TWh in residential buildings and 13 TWh in non-residential buildings, see Figure 21.

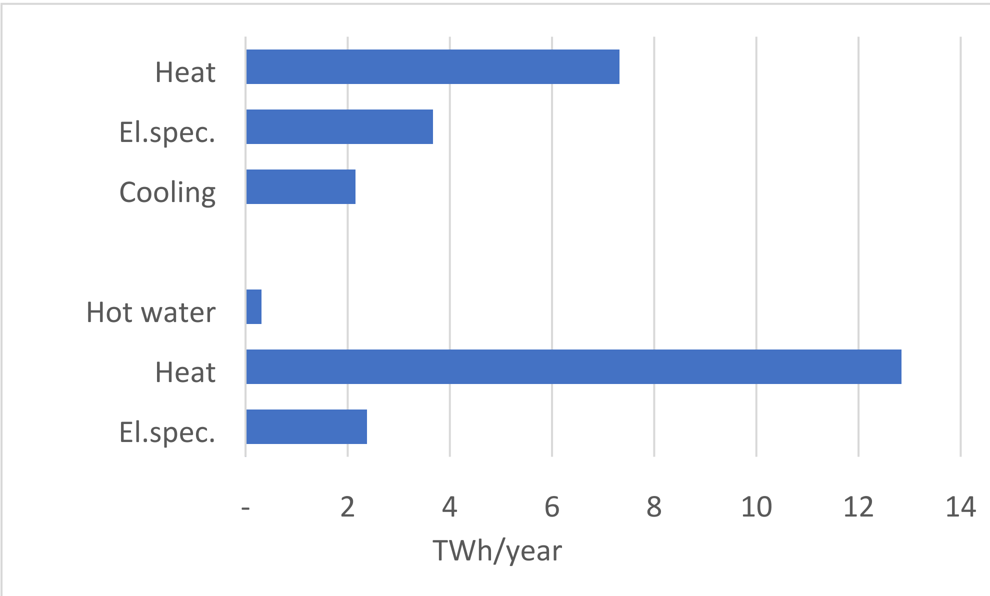


Figure 21 Potential for energy efficiency measures in 2025 in residential and non-residential buildings (TWh/year)

5.3 Road Transport

The road transport is divided into five different types and are listed in Table 22 together with a short description.

Table 22 Description of the different road transport demand types

Type	Name in TIMES	Description
Cars	TCAR	Vehicles transporting up to 9 persons including driver. Motorhomes, taxis and ambulances are also included in this group.
Vans	TVAN	Vehicles designed for carriage of goods which are not exceeding 3,5 ton in gross vehicle weight. It corresponds the Norwegian Public Roads Administrations vehicle group N1. Combined cars which are designed for both carriage of person and goods are also included in this category.
Trucks	TTRUCK	Vehicles above 3,5 ton designed for carriage of goods.
Tractor units with semi-trailer	TTRAILER	Vehicle designed for transporting a semi-trailer.
Bus	TBUS	Vehicles transporting 10 persons or more.

5.3.1 Demand

The demand towards 2050 is based upon the forecasts made in the national transport plan (NTP) 2018-2029 and is shown in Figure 22.

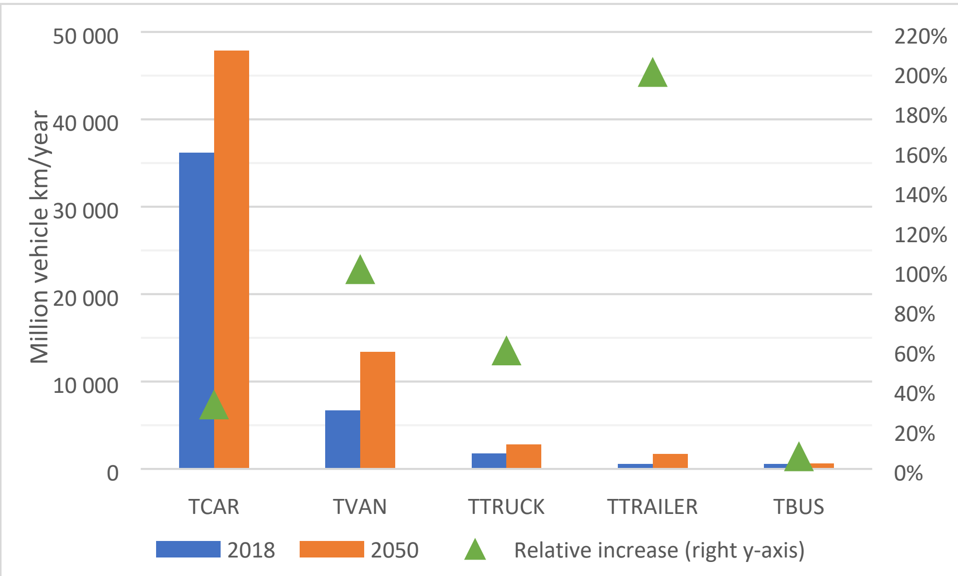


Figure 22 Shows the demand for the default scenario (NTP) in 2018 and 2050 in million vehicle-km per year (left y-axis) and the relative change (right y-axis)

5.3.2 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 23.

Table 23 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 busses.	XXX-GAS	GAS

Various of the powertrains have several commodities as input and limitations are set for some of them of how small or big share they can be of the total input. An overview of set limitations is shown in Table 24. Biofuels represented 12% of volumetric fuel demand for road transport in 2018 [53], 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 [54]. This implicates an actual blending with minimum 16% of biofuels in 2020 and it is fixed to this limit in the model. While 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 [55] of 30% electricity share, based on measured data from www.spritmonitor.de, are used. As shown in Table 24, the value is assumed to be constant in IFE-TIMES-Norway until 2050.

Table 24 Share of commodities for certain powertrains.

		Start year	2020	2040	2050
BIO-FUEL input for ICE	Max	12%	16%	100%	
	Min	12%	16%	20%	
Electricity input in plug-in hybrid	Max	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 23 is shown an overview of which powertrains are considered for each type of road transport demand. There is a small share of gas-powered vehicles such as waste collection trucks and others which are operating on biogas. Due to their small share in the total vehicle fleet and limited expected growth potential, they are not modelled in IFE-TIMES-Norway.

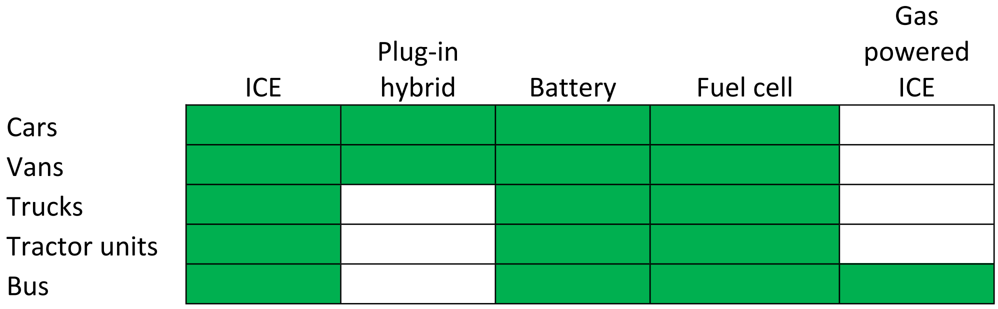


Figure 23 Matrix of powertrains applied for the different road transport demand

Battery vehicles are the most efficient and in short term most affordable solution for an emission free drivetrain. However, for heavy-duty applications they fall short on either driving range per charge or in case the driving range is extended by larger batteries they are reducing the payload capacity. As heavy-duty vehicles are used in a commercial setting where delivery time and payload are central parameters, their penetration in the segment has a limitation. To quantify this limitation, detailed heavy-duty vehicle driving patterns developed by TØI [56] are adapted and used in IFE-TIMES-Norway. IFE has received driving patterns divided by truck and tractor units shown in Table 25 and Table 26. Based on the technical performance of the vehicles in current demo projects in Norway, a market penetration of approx. 1% can be achieved [56].

The market penetration of battery vehicles is assumed to increase as both batteries and their integration in trucks will evolve. By 2030 it is assumed that trucks and tractor units will be able to serve distances up to 300 km and in the long-term (2040) an average daily range up to 500 km will be reached. It gives a market share for trucks and tractor units in 2030 of approx. 75% and 40% respectively. By 2040 the share increase to 87% and 58%, respectively according to Table 25 and Table 26. It is a simplified method to estimate market potential for battery trucks and tractor units as with a well-developed charger infrastructure the battery vehicles will be able to reach higher daily mileages. While other vehicles which have a shorter daily route in km might have an extremely demanding/continuous demand profile or are required to occasionally operate continuously for large distance and thereby cannot rely on only battery technology. These shares based on average max daily mileage is an uncertain parameter, and where relevant, a sensitivity analysis can be made by changing the assumed max average daily mileage battery trucks will be able to deliver.

Table 25 The distribution of daily mileage with different engine power for trucks. Disaggregated from [56].

Engine power (HP)	Up to 100 km	100-200 km	200-300 km	300-400 km	400-500 km	500 km +	Total sum
100	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	**0.4%**
200	4.4%	3.8%	1.9%	1.0%	0.3%	0.3%	**11.7%**
300	4.7%	4.7%	1.8%	1.2%	0.3%	0.4%	**13.0%**
400	6.9%	6.3%	4.2%	1.4%	0.6%	1.9%	**21.4%**
500	13.0%	8.0%	5.4%	2.8%	3.6%	7.8%	**40.5%**
600	2.5%	1.2%	0.9%	0.3%	0.3%	1.1%	**6.3%**
700	2.7%	1.0%	0.5%	0.6%	0.4%	1.6%	**6.7%**
Total sum	**34.2%**	**25.2%**	**14.7%**	**7.3%**	**5.5%**	**13.1%**	**100.0%**

Table 26 The distribution of daily mileage with different engine power for tractor units. Disaggregated from [56].

Engine power (HP)	Up to 100 km	100-200 km	200-300 km	300-400 km	400-500 km	500 km +	Total sum
300	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	**0.3%**
400	1.6%	1.8%	1.0%	0.5%	0.5%	2.6%	**7.9%**
500	11.6%	8.7%	8.2%	5.8%	7.6%	31.1%	**73.1%**
600	1.7%	0.9%	0.9%	1.0%	1.4%	4.8%	**10.7%**
700	1.1%	0.8%	1.0%	0.5%	1.0%	3.7%	**8.1%**
Total sum	**16.1%**	**12.3%**	**11.1%**	**7.7%**	**10.6%**	**42.1%**	**100.0%**

Some technologies of vans and busses are limited to give a more realistic development in certain model scenarios, see Table 27.

Table 27 Upper market share limitations of vans and buses

Technology	Market share	
	2030	**2040**
TVAN-ELC	15%	100%
TVAN-PLUG	15%	100%
TBUS-GAS	10%	50%

5.3.3 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 [57]. 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 28. In the same table are also shown how existing stock of battery vehicles are distributed with a greater density in the southern parts of Norway.

Table 28 How transport demand and existing stock of battery vehicles are distributed over the regions

	Transport demand	Battery vehicle distribution
NO1	42%	45%
NO2	24%	23%
NO3	16%	12%
NO4	9%	2%
NO5	9%	18%
Total	100%	100%

5.3.4 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.

5.3.4.1 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 [58]. 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 [33]. 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 discomposes 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 [59]. When applying trends from [59]; the fuel consumption relationship between powertrains and development over time is based in 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 [55]. An overview of the values used are shown in Table 29.

Table 29 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 [33]	0.39	31% improvement from 2020 according [59]
TCAR-ICE_0	0.59	4% increase from new investment		
TCAR-ELC	0.19	Average small and big car from [33]	0.12	12% improvement from 2020 according [59]
TCAR-ELC_0	0.19	Same as new investment		
TCAR-PLUG	0.42	Relative improvement from ICE according to [59]	0.32	24% improvement from 2020 according [59]
TCAR-PLUG_0	0.44	4% increase from new investment		
TCAR-H2	0.33	[55]	0.28	[55]

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 [60].

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 30 is shown the final values used for powertrains for TVAN in IFE-TIMES-Norway.

Table 30 Energy consumption for vans (TVAN)

Name in TIMES	Start year		2050	
	kWh/km	Source	kWh/km	Source
TVAN-ICE	0.59	Average of light and heavy van from [33]	0.40	Same improvement as for TCAR-ICE
TVAN-ICE_0	0.73	25% increase from new investment		
TVAN-ELC	0.19	Average of light and heavy van from [33]	0.12	Same improvement over time as for TCAR-ELC
TVAN-PLUG	0.42	Same relative improvement as for TCAR-PLUG relative to TCAR-ICE	0.32	Same improvement over time as for TCAR-PLUG
TVAN-H2	0.33	Same relative improvement as for TCAR-H2 relative to TCAR-ICE	0.28	Same improvement over time as for TCAR-H2

Trucks and trailers (TTRUCK and TTRAILER)

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 approach selected is based on an energy efficiency for ICE representative for Norway and is adapted from Klimakur 2030 [33] both for TTRUCK and TTRAILER. In Klimakur 2030 the energy consumption for tractor units is relatively high compared to other sources such as [56], [61] and TØI BIG model.

The truck segment in Klimakur 2030 is divided into local/regional, mass and long-haul transport. The data from Klimakur 2030 is adapted to the IFE-TIMES-Norway model by assuming that transport work for local/regional and mass transport is made only by trucks and all long-haul transport is made only by tractor units.

The local/regional and mass transport has different energy efficiencies. Based on the emissions from each truck group stated in Klimakur 2030 and adjusted for a longer travelled distance per emitted ton CO_2 for the local/regional transport due to less energy demanding transport, the fuel consumption input to IFE-TIMES-Norway is weighted 70%/30% between local/regional and mass transport.

For zero-emission heavy-duty technologies there is present only a limited amount of 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. [62]. 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. [62]. 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.

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 of TTRUCK and TTRAILER 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 31.

Table 31 Energy consumption for heavy-duty truck and tractor units (TTRUCK and TTRAILER)

Name in TIMES	Start year	
	kWh/km	Source
TTRUCK-ICE	3.96	Weighted consumption of local/regional and mass transport from [33]
TTRUCK-ICE_0	4.35	4% increase from new investment
TTRUCK-ELC	1.24	Relative improvement from ICE in a short-haul truck according [62]
TTRUCK-H2	1.90	Relative improvement from ICE in a short-haul truck according [62]
TTRAILER-ICE	5	Long-haul trucks from [33]
TTRAILER-ICE_0	5.1	2% increase from new investment
TTRAILER-ELC	2.74	Relative improvement as from H2 to ELC short-haul truck according to [62]
TTRAILER-H2	4.15	Relative improvement from ICE in a long-haul tuck according [62]

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 [56, 63] provides fuel consumption for the complete set of technologies currently (2016-2019) and short/middle term 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 32.

Table 32 Energy consumption for busses (TBUS)

Name in TIMES	Start year		2025	
	kWh/km	Source	kWh/km	Source
TBUS-ICE	4.20	[56]	4.10	[56]
TBUS-ICE_0	4.28	2% increase from new investment		
TBUS-GAS	5.38	Increase relative to ICE Euro IV according to [63]	5.25	Increase relative to ICE Euro IV according to [63]
TBUS-GAS_0	5.48	2% increase from new investment		
TBUS-ELC	2.30	[56]	2.10	[56]
TBUS-H2	3.33	[56]	3.33	[56]

CO_2 emissions in start year

The greenhouse gas emissions in the start year is adjusted to match the national emissions from road transport in 2018. As in IFE-TIMES-Norway the existing stock of vehicles are modelled relatively coarse, small mismatches in numbers is present, and is presented in Table 33.

Table 33 Comparison of emissions from road transport in 2018 from Statistics Norway (SSB) [64] and IFE-TIMES-Norway start year

		Statistics Norway	IFE-TIMES-Norway
		Mill.ton CO2	Mill.ton CO2
Car		**4.64**	**4.81**
Light transport		**1.40**	**1.14**
Heavy transport		**2.80**	**2.95**
	Truck		1.70
	Trailer		0.67
	Bus		0.59
2-wheelers		**0.11**	
Total emission from road transport		**8.95**	**8.91**

5.3.4.2 Maintenance costs

The maintenance costs (see Table 34) are based on values specified in Klimakur 2030 [33] 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, in start year, the same maintenance cost is set as for plug-in vehicles, but the maintenance cost based on fuel cell technology remains a novel technology and might require closer follow up in near term, while 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 34 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	Start year	0.98		0.98	0.98	
TTRAILER	Start year	0.79		0.79	0.79	
TBUS	Start year	2.20		1.60	1.90	2.20
	2030				1.60	

5.3.4.3 Investment cost

The VAT and purchase fees are included only for cars due to it is expected to present in best ways 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 is 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. [58]

The purchase price of ICE and EV vehicles are based on Klimakur 2030 [33]. The costs are just as 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 “5.3.4.1 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 35.

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 [58].

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 35 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 [33]	241,643	Average small and large car [33]
TCAR-ELC	480,500	Average small and large car [33]	248,489	Average small and large car [33]
TCAR-PLUG	306,381	Trend relative to ICE from [58]	287,546	Trend relative to ICE from [58]
TCAR-H2	765,167	Trend relative to ICE from [58]	370,661	Trend relative to ICE from [58]

Vans (TVAN)

Klimakur 2030 provides cost for a large and small van for both ICE and battery powertrains. While for other powertrains is applied the same relative cost trends as for TCAR based on the similarities between TVAN and TCAR discussed in chapter “5.3.4.1 Fuel consumption”. The summary of the costs for TVAN in IFE-TIMES-Norway is shown in Table 36.

Table 36 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 [33]	236,240	Average small and large van [33]
TVAN-ELC	506,000	Average small and large van [33]	248,489	Average small and large van [33]
TVAN-PLUG	308,254	Trend relative to ICE from [58]	281,116	Trend relative to ICE from [58]
TVAN-H2	769,842	Trend relative to ICE from [58]	362,373	Trend relative to ICE from [58]

Trucks and trailers (TTRUCK and TTRAILER)

The investment cost of ICE and battery trucks and trailers are based on Klimakur 2030 for 2020 and 2030. The adaptation of the different heavy-duty transport types used in Klimakur 2030 to IFE-TIMES-Norway is based on the same methodology as described in chapter “5.3.4.1 Fuel consumption”.

The Klimakur 2030 data is complemented with data presented by Fulton et.al. [62] from UCDavis in report “Technology and Fuel Transition Scenarios to Low Greenhouse Gas Futures for Cars and Trucks in California” to identify the relative increase in costs of fuel cell powered truck and tractor unit versus ICE powered vehicles. However, the cost reduction of them are very large during the 2020’s and is assumed to be too optimistic. Therefore, the relative cost development of fuel cell trucks and tractor units stated for 2030 is delayed to 2040 in IFE-TIMES-Norway. The same source is used to predict the cost development of ICE and the other powertrains cost relative to it in 2050. The summary of the used costs for TTRUCK and TTRAILER in IFE-TIMES-Norway is shown in Table 37.

Table 37 Investment costs for TTRUCK and TTRAILER exclusive taxes and fees

Name in TIMES	NOK	Source
Start year		
TTRUCK-ICE	1,050,000	Weighted cost of local/regional and mass transport from [4]
TTRUCK-ELC	2,262,859	Weighted cost of local/regional and mass transport from [4]
TTRUCK-H2	4,058,824	Trend relative to ICE from [8]
TTRAILER-ICE	1,100,000	According long-haul truck from [4]
TTRAILER-ELC	3,600,536	According long-haul truck from [4]
TTRAILER-H2	3,932,021	Trend relative to long-haul ICE from [8]
2030		
TTRUCK-ICE	1,071,971	Weighted cost of local/regional and mass transport from [4]
TTRUCK-ELC	1,146,109	Weighted cost of local/regional and mass transport from [4]
TTRAILER-ICE	1,123,017	According long-haul truck from [4]
TTRAILER-ELC	1,680,536	According long-haul truck from [4]
2040		
TTRUCK-H2	1,720,588	Trend relative to ICE 2030 from [8]
TTRAILER-H2	1,439,000	Trend relative to ICE 2030 from [8]
2050		
TTRUCK-ICE	1,121,446	Relative change from 2030 according to [8]
TTRUCK-ELC	1,137,938	Trend relative to ICE from [8]
TTRUCK-H2	1,278,119	Trend relative to ICE from [8]
TTRAILER-ICE	1,171,544	Relative change from 2030 according to [8]
TTRAILER-ELC	1,185,419	Trend relative to ICE from [8]
TTRAILER-H2	1,317,625	Trend relative to ICE from [8]

Battery and hydrogen powertrains for heavy-duty trucks have by 2020 not yet arrived to the market in large scale and some of them are only expected to arrive in coming years, therefor the starting year at which they can be deployed in the model has been adjusted as presented in Table 38.

Table 38 Starting year for investment in battery and hydrogen powered trucks and tractor units.

Type of powertrain	Starting year
TTRUCK-ELC	2020
TTRUCK-H2	2025
TTRAILER-ELC	2022
TTRAILER-H2	2025

Buses (TBUS)

The investment cost of bus until 2025 is based on TØI report “Klima-og miljøvennlig transport frem mot 2025” [65]. 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. [62] from UCDavis. The summary of the used costs for TBUS in IFE-TIMES-Norway is shown in Table 39.

Table 39 Investment costs for TBUS exclusive taxes and fees

Name in TIMES	NOK	Source
Start year		
TBUS-ICE	2,000,000	[65]
TBUS-GAS	2,200,000	[65]
TBUS-ELC	4,500,000	[65]
TBUS-H2	8,000,000	[65]
2025		
TBUS-ICE	2,000,000	[65]
TBUS-GAS	2,200,000	[65]
TBUS-ELC	3,000,000	[65]
TBUS-H2	4,000,000	[65]
2050		
TBUS-ICE	2,116,000	Relative change from 2025 according to [8]
TBUS-GAS	2,435,000	Trend relative to ICE from [8]
TBUS-ELC	2,116,000	Trend relative to ICE from [8]
TBUS-H2	2,290,000	Trend relative to ICE from [8]

5.3.4.4 Lifetime and annual mileage

Lifetime and annual mileage are two additional input variables used in IFE-TIMES-Norway. To select these parameters, it shall be considered when a new investment is made in IFE-TIMES-Norway, it is assumed to provide annually same amount of vehicle km until end of its lifetime. In real word however the annual mileage is highest the first years and then drops considerably with the age of the vehicle. In Figure 24 it is represented as accumulated traffic volume with the age of the vehicle, where data is clustered in 5-years' time bins. 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. The tractor units are accumulating very fast the traffic volume during the first years, therefore a year in the middle of the 5-years' time bins was chosen to present a suitable lifetime of this vehicle type. The selected vehicle lifetimes are presented in Table 40.

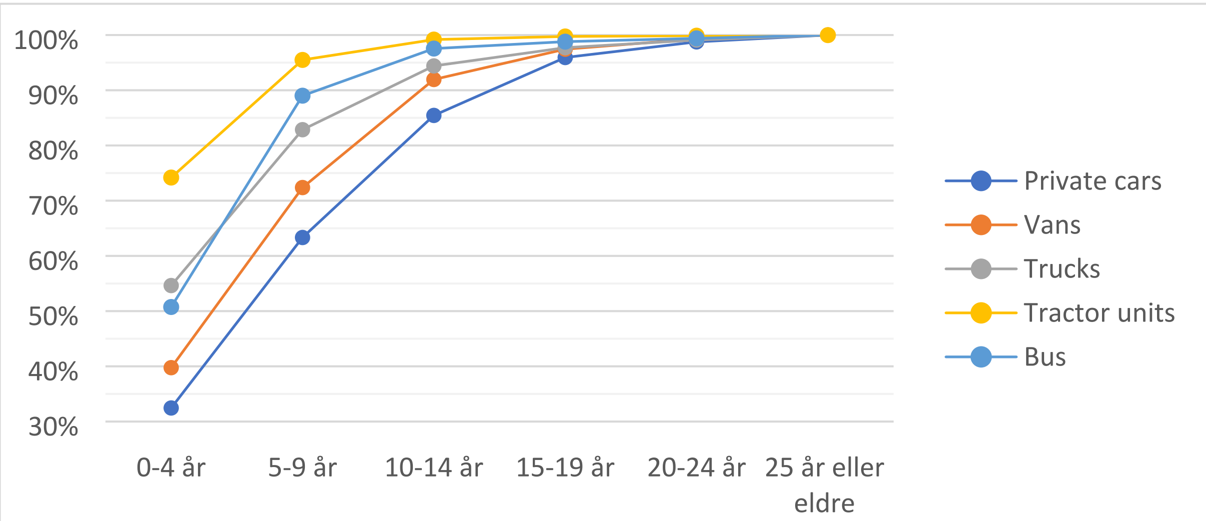


Figure 24 Accumulated traffic volume of each vehicle type depending of age, based on data from [60]

Same 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 40.

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, omitting usage of old and very old vehicles which are past the lifetime set in IFE-TIMES-Norway.

Table 40 Lifetime and annual mileage used in IFE-TIMES-Norway

Vehicle type	Lifetime (years)	Average annual mileage (km)
TCAR	15	13,200
TVAN	15	15,300
TTRUCK	10	38,400
TTRAILER	8	75,300
TBUS	10	41,800

5.3.5 Growth limitation

The investments in new capacity made in TIMES is based on the lowest lifetime cost option available. It means that when a new technology becomes the cheapest option, the entire investment in new capacity is shifted to this new technology. A 100% switch between powertrains from one year to another is assumed as unrealistic for vehicle sales and thereby a limitation is placed on how large increase in new capacity can be made for the different powertrains. A similar problem and limitations are implemented for the decrease in year-to-year investment in existing technology. These limitations are made with the help of NCAP, GROWTH user constrain.

For all technologies are set a bound which limits the change in new capacity installed to be between +30% and -30% from previous year. The limitation in year to year increase is based on the most optimistic increase in sales shares of zero-emission vans presented in figure E.16 in [66] considering the growth of the market share between approx. 10% to 90%.

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. On the other hand, for technologies without an existing stock a predefined first investment starting level of 1 million vehicle km per year.

5.3.6 Energy efficiency depending on outside temperature and charging patterns

When simulating a large share of EV's instead of ICE vehicles, it is worth to consider their technical difference. In contrast to the ICE vehicle, the BEV's are much more energy efficient, however, EVs lack sufficient waste heat to provide substantial cabin heating. It leads to larger fluctuation in energy demand depending on season for BEV's in comparison with an ICE vehicle.

A literature study was made on this topic and is attached as Appendix B. From the existing studies a range was estimated of how much the energy efficiency could drop and in IFE-TIMES-Norway the best-case scenario was adopted (the smallest drop in energy efficiency). The correlation is shown in Figure 25 in energy demand per km as a function of outside temperature. Same seasonal change in efficiency is assumed among all the regions and the seasonal temperature used is weighted among the different regions based on vehicles fleet concentration. Due to the similarity between cars and vans, the same correlation is also assumed for battery powered vans.

The increased energy demand for TTRUCK and TTRAILER is based on that the cabin will require 5kW cabin heater at -20°C and linearly reduced to no heating at +20°C according to [67]. In this analysis has not been considered increased energy demand due to higher density of air at low temperatures or due to increased rolling resistance of more water, snow or slush on road at colder climate.

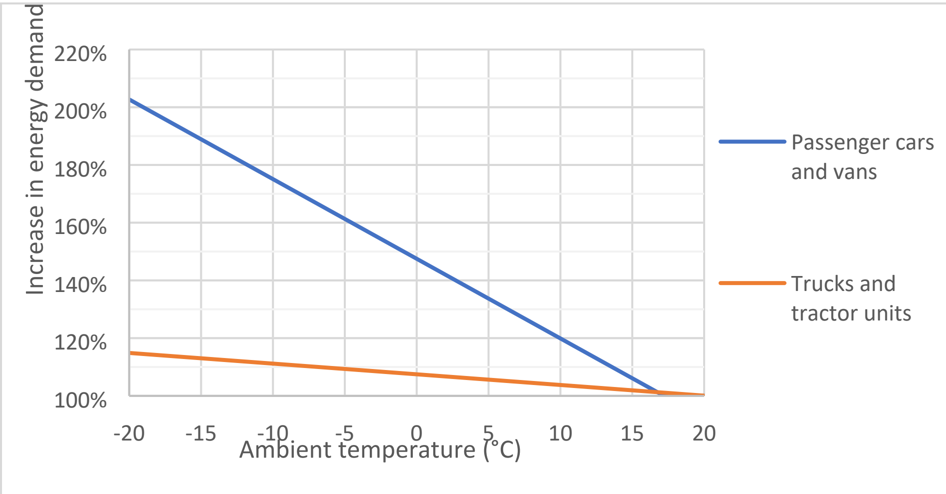


Figure 25 Correlation of how the energy demand per km of light- and heavy-duty vehicles increases with decreasing ambient temperature.

5.3.7 Charging infrastructure for EV's

All electrical vehicles are depending on having available charging infrastructure, which brings an additional cost to the system in comparison with current well-established petrol filling station infrastructure. As a first attempt to include this cost in the model, three different chargers for private vehicles and vans are included: Residential, Commercial and Fast charging. The Commercial charging is defined as slow charging that it is done close to commercial buildings, with intention to represent that the car is charged at work. An overview of the different chargers' main parameters is shown in Table 41.

For residential and commercial charger, it is assumed the cost of a charger with max output <11kW and assumed average output of 7kW. For fast charging it is assumed costs of 50kW charger at start year which is fully replaced by 150kW charger in 2025. For heavy-duty vehicles the costs are based on 600 kW fast charger, for heavy-duty depot charger the investment costs per kW is similar. The investment costs are taken from Klimakur 2030.

Fast chargers are built to recharge the battery as fast as possible and due to the battery's limitation; they can only operate at full output at a fraction of the charging time. Due to this fact, a fast charger for light-duty vehicles is assumed in average to provide 60% of rated capacity and for heavy-duty vehicles with considerably larger batteries the average power is set to 80% of rated capacity.

The charger is converting the AC current from the grid to DC current which is fed into the battery. It requires to both rectify from AC to DC and to transform between different voltage levels and power for control unit. Empiric studies shows that a low power output built-in charger for EV's has an efficiency of approx. 80% [68, 69]. 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 [70].
The lifetime is assumed and needs to be reviewed later.

Table 41 Type of chargers used in IFE-TIMES-Norway and their characteristics.
Based on [33, 68, 70] and own assumptions.

Vehicle type	Type of charger	Commodity used	Efficiency	Investment costs (NOK/kW)	Lifetime (year)
Light-duty	Residential	ELC-LV, ELC-PV-RES	80%	2857	15
Light-duty	Commercial	ELC-LV, ELC-PV-COM	80%	2857	15
Light-duty	Fast charging	ELC-LV	90%	In 2018: 12000 In 2025: 5000	15
Heavy-duty	Fast charging	ELC-LV	90%	8300	15

5.4 Transport by rail, sea and air

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 26 and it is mainly based on NTP [71]. The increase in sea transportation is 50%, in rail transportation 42% and in air and other 25%.

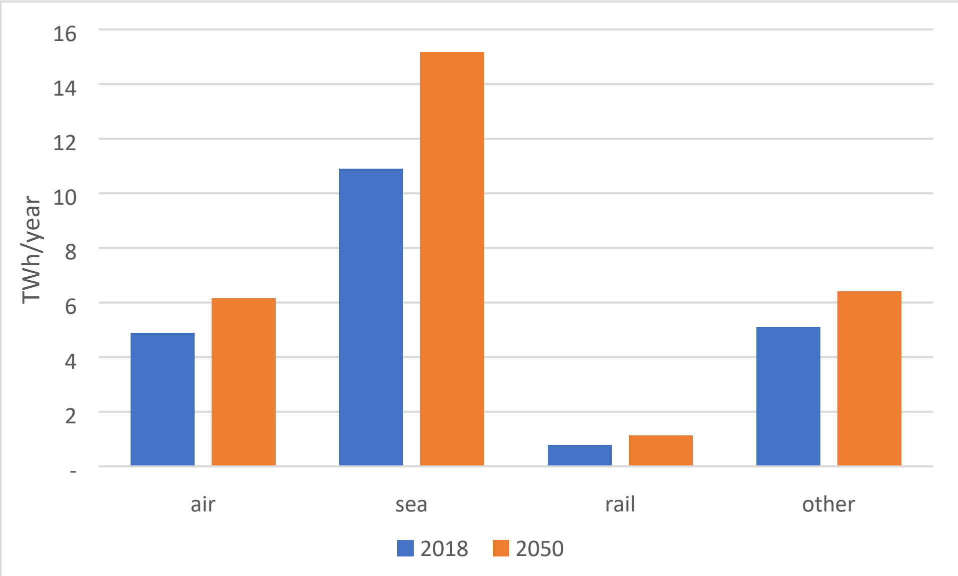


Figure 26 Energy demand of non-road transport in 2018 and 2050, TWh/year

Energy use in rail transport and other transport is modelled as a share of different energy carriers. In the regions NO1, NO2 and NO5, 100% of electricity is used by the railway. In region NO3 the electricity share for railway is 8% and in NO4 the 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.

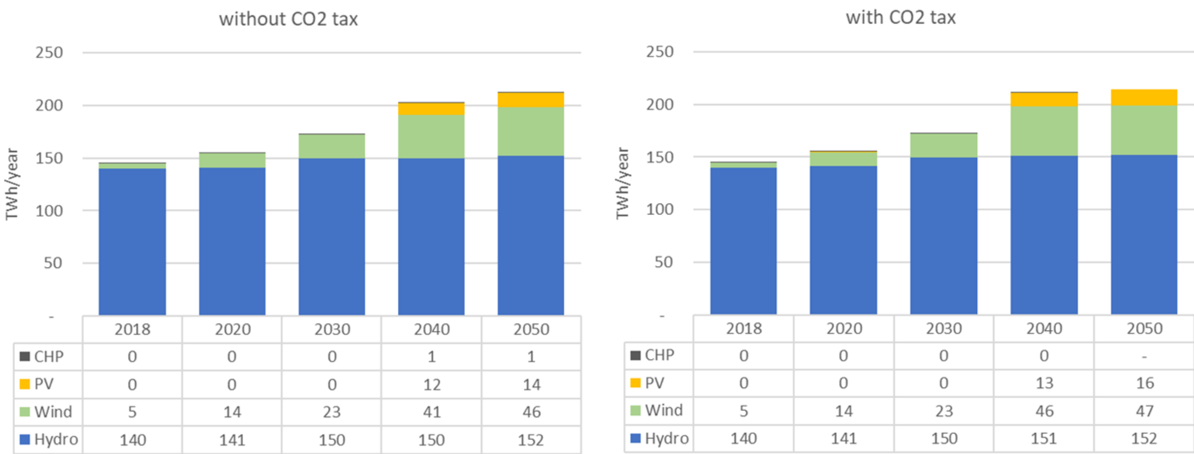
Sea transport uses internal combustion engines in the base year. They are assumed to use less than 5% biofuels in the base year, increasing to 10-20% in 2020 and 10-100% in 2040. These vessels can be replaced by investment in hydrogen or battery electric vessels from 2025. The efficiency of hydrogen is assumed to be 20% better than conventional vessels and battery electric vessels are assumed to be twice as effective as the ICE vessels. The market share of battery electric vessels is limited to 33% in 2040 and the maximum share of hydrogen vessels is linearly increasing from zero in 2020 and unlimited in 2040.

6 Results

Results of analyses of the Base Case with and without CO_2-taxes are presented here, based on the assumptions presented in this report. A CO_2 tax of 1000 NOK/ton CO_2 is applied from 2025 increasing to 10 000 NOK/ton CO_2 in 2050 (no tax before 2025). CCS is not included in the analyses. These results are included in this report as an example of results of analyses with the IFE-TIMES-Norway model. The results highly depend on assumptions and input data to the model and is normally discussed and analysed in more detail than presented here.

6.1 Electricity

In a normal year, the total electricity production increases from 143 TWh in 2018 to 213 TWh in 2050 without CO_2-taxes and to 214 TWh with CO_2-taxes, see



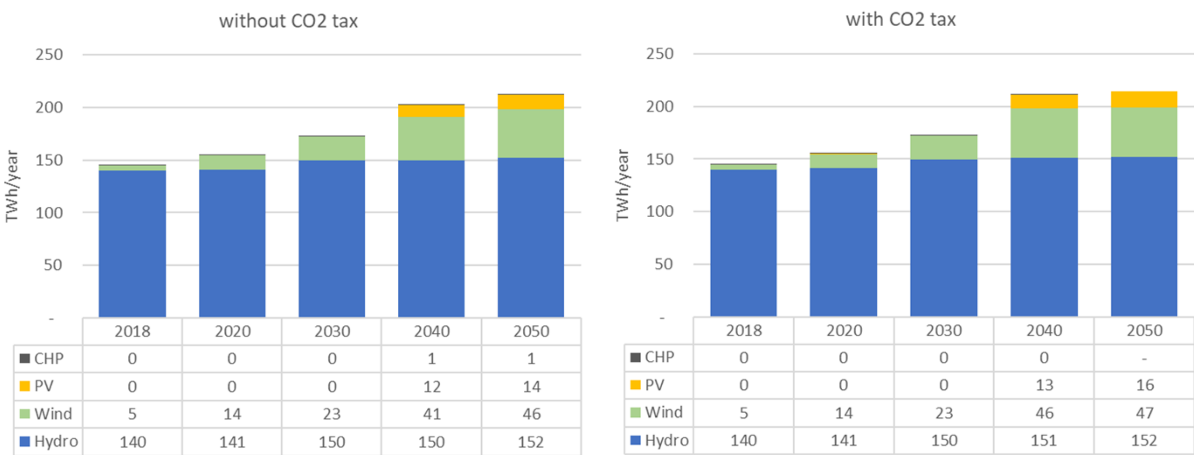
without CO2 tax

	2018	2020	2030	2040	2050
CHP	0	0	0	1	1
PV	0	0	0	12	14
Wind	5	14	23	41	46
Hydro	140	141	150	150	152

with CO2 tax

	2018	2020	2030	2040	2050
CHP	0	0	0	0	-
PV	0	0	0	13	16
Wind	5	14	23	46	47
Hydro	140	141	150	151	152

Figure 27. Hydro power generation increase with 12 TWh from today until 2050, wind power increase with 41 TWh, and PV with 14-16 TWh.



without CO2 tax

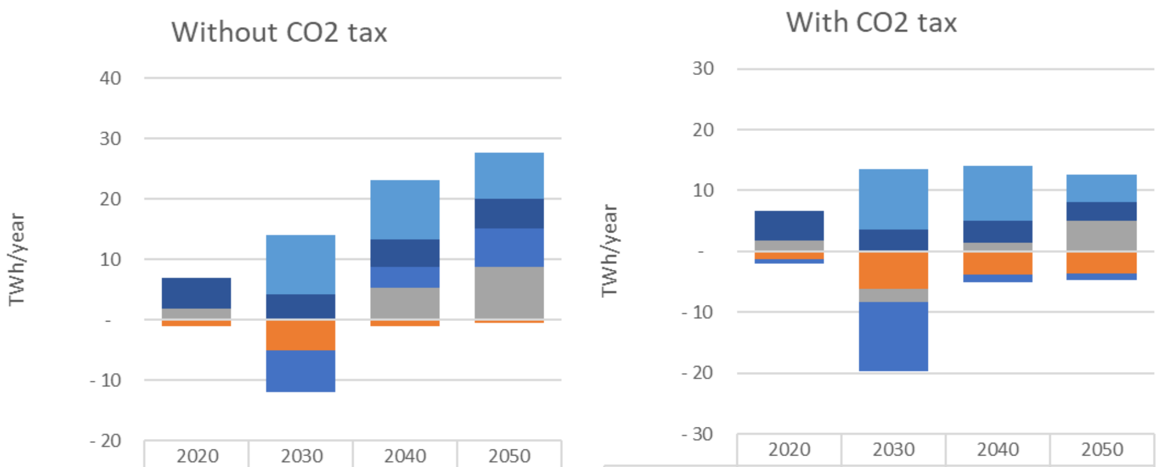
	2018	2020	2030	2040	2050
CHP	0	0	0	1	1
PV	0	0	0	12	14
Wind	5	14	23	41	46
Hydro	140	141	150	150	152

with CO2 tax

	2018	2020	2030	2040	2050
CHP	0	0	0	0	-
PV	0	0	0	13	16
Wind	5	14	23	46	47
Hydro	140	141	150	151	152

Figure 27 Electricity production without and with CO2 tax, TWh/year

The power trade with neighboring countries is much higher in analyses without CO_2 tax, see Figure 28. In 2040 and 2050, the net export of electricity is 27 TWh without CO_2 taxes and with taxes the net trade is 8 TWh in 2040 and 6 TWh in 2050. With CO_2 taxes, Norway is a net importer of electricity in 2030 (7 TWh).



Without CO2 tax (TWh/year)

	2020	2030	2040	2050
UK	-	10	10	8
Netherlands	5	4	5	5
Sweden	0	- 7	4	6
Germany	2	0	5	9
Denmark	- 1	- 5	- 1	- 0

With CO2 tax (TWh/year)

	2020	2030	2040	2050
UK	-	10	9	4
Netherlands	5	4	4	3
Sweden	- 1	- 11	- 1	- 1
Germany	2	- 2	1	5
Denmark	- 1	- 6	- 4	- 4

Figure 28, Power trade with neighboring countries, TWh/year

The electricity use by end-use sector from 2018 to 2050 is presented in Figure 29. Commercial buildings show a slight decrease, residential buildings a small increase in the start, while industry increase the electricity use the most. With CO2-taxes, the electricity use in industry increase by 25 TWh from 2018 to 2050. This is linked to increased activity in aluminum production, chemical production, data centers and electrification of offshore activities.

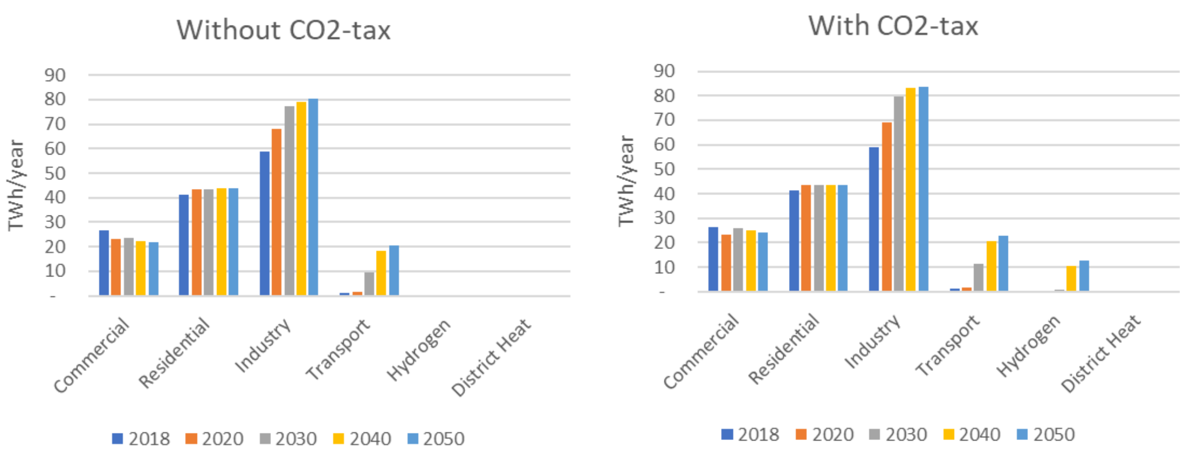


Figure 29 Electricity use per sector, TWh/year

6.2 Overall energy use

The energy use by energy carrier and end-use sector is presented in Figure 30. The energy use of buildings decreases by 6% from 2018 to 2050, in industry it increases by 10-11% and in transport the decrease is 19% without CO2 taxes and 31% with CO2 taxes.

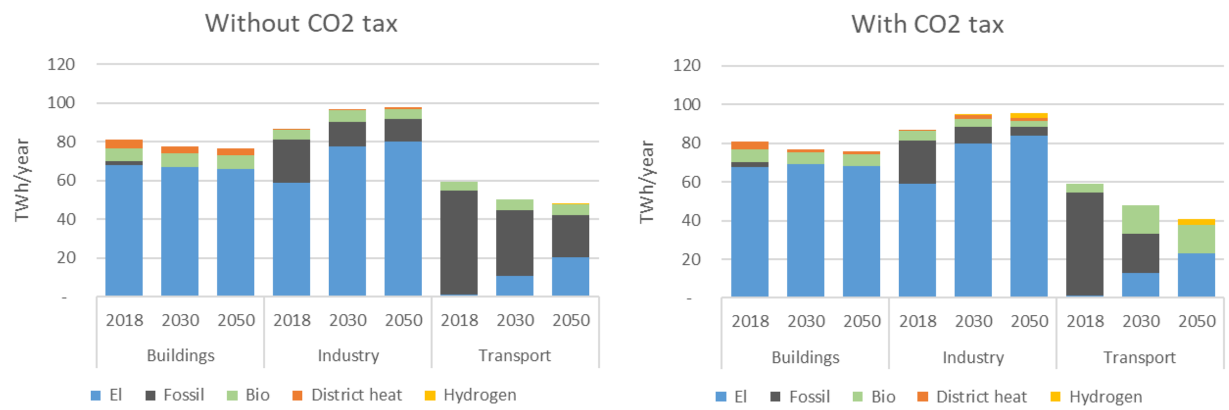


Figure 30 Energy use by energy carrier and end-use sector, TWh/year

6.3 Road transport

An example of the use of energy carriers in road transport for different modes is presented in Figure 31. Without any CO2 taxes, almost no hydrogen is used, and fossil fuels are still used in heavy transport in 2050. When applying CO2 taxes, fossil energy is phased out and replaced by battery electric vehicle when possible, otherwise biofuels and/or hydrogen is used.

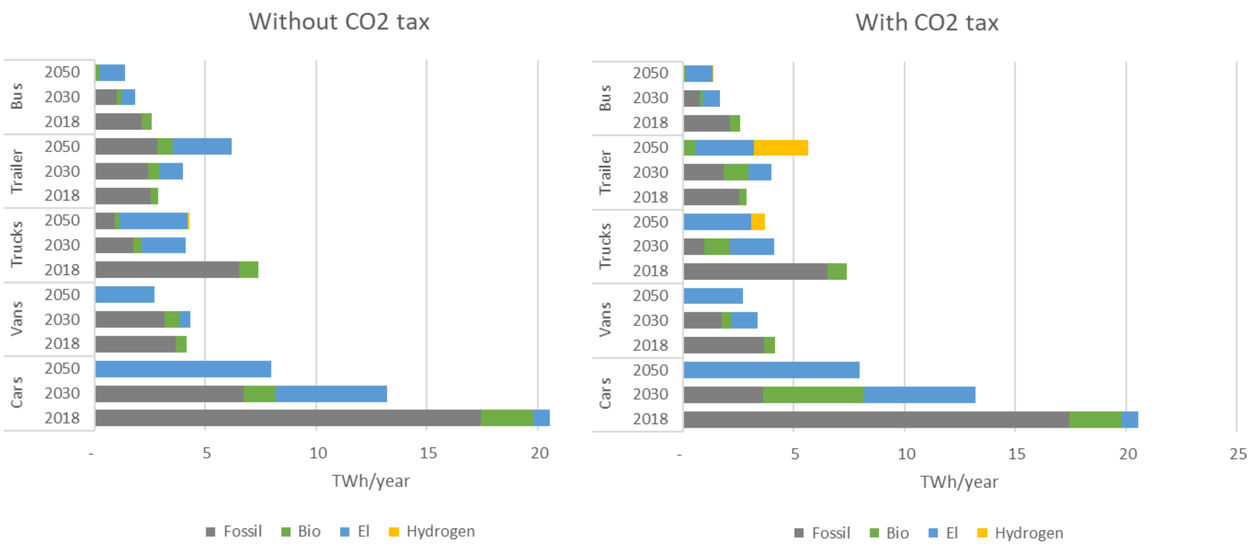


Figure 31 Energy use by energy carrier and road transport mode, TWh/year

6.4 CO2 emissions

IFE-TIMES-Norway does not include all Norwegian GHG emissions, emissions from offshore petroleum activities are excluded as well as non-energy related emissions. The decrease in CO2 emissions in the two example analyses is presented in Figure 32. Without CO2 tax, the CO2 emissions is reduced by 46% or 12 million tons of CO2 from 2018 to 2050. With CO2 taxes, the reduction is 77% or 20 million tons of CO2/year.

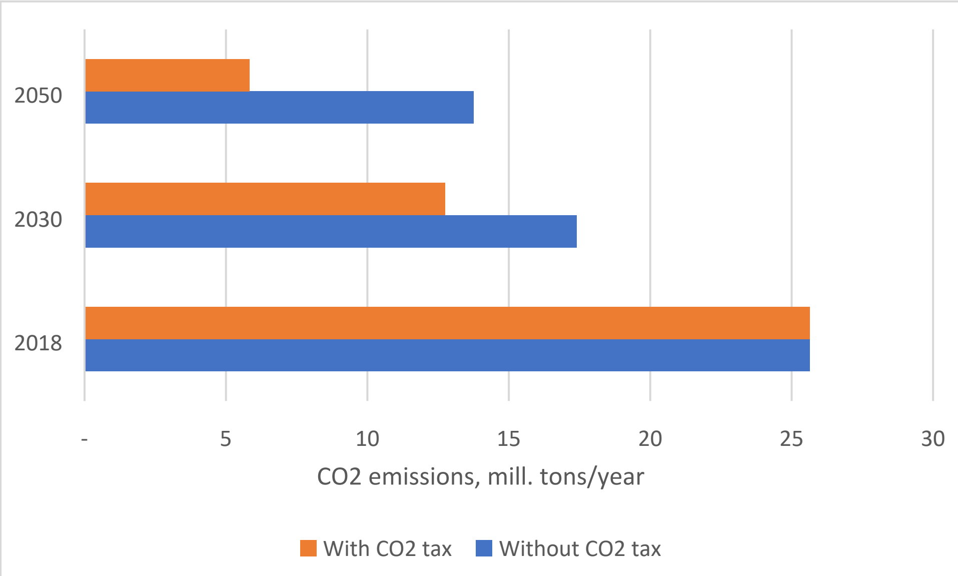


Figure 32 CO2 emissions in analyses without and with CO2 tax, million tons of CO2/year

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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 10 MW_{el} installed capacity while costs for the decentralized unit are based on a 1 MW_{el} size electrolyzer.
The costs are composed from three parts: electrolyzer, compressor skid and other costs. The costs of electrolyzer is taken from [1] 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. [2] 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 [3] and refined in [4]. The required compressor capacity to reach the set pressure is based on adiabatic compression defined as

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

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 [5]. In addition, a mechanical efficiency of 70% is added and a compressor redundancy is set to 3 x 50%, except for 1MW_{el} PEM electrolyzer for which it is sized for 2 x 100%. The compression power, size and cost of compressors and the cost of compressor per installed electrolyzer effect is given in Table A-1.

Table A-1 Compressor sizing and compressor cost per installed kW of electrolyzer capacity

		Compressor size (total)	Size per compressor	Compressor costs	Compressor costs as per kW installed electrolyzer
		kW_{comp}	kW_{comp}	NOK/kW_{comp}	NOK/kW_{ely}
10 MW	PEM	159	79	45000	1,072
	Alkaline	391	195	45000	2,638
1 MW	PEM	16	16	90000	2,143
	Alkaline	39	20	75000	4,396

The other cost consists of [6]:

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 60% and 38% of CAPEX for 1 MW_{el} and 10 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 [2] 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-2.

Table A-2 Cost span of electrolyzers from [2] 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 [7] 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-3 is summarized the cost used for each component (electrolyzer, compressor and other costs) and the sum of them used as input value in IFE-TIMES-Norway.

Table A-3 The cost for the different electrolyzers for different years shown in NOK per installed kW_{el}

			2018	2030	2050
10 MW el	PEM	Electrolyzer -	7406	5497	2777
		Compressor -	935	440	374
		Other costs	3170	2256	1198
		Total costs	**11511**	**8192**	**4349**
	Alkaline	Electrolyzer -	5925	3879	2821
		Compressor -	2318	1089	927
		Other costs -	3132	1888	1424
		Total costs	**11375**	**6857**	**5173**
1 MW el	PEM	Electrolyzer -	12363	9175	4636
		Compressor -	3118	1466	1247
		Other costs	9289	6385	3530
		Total costs	**24770**	**17026**	**9413**
	Alkaline	Electrolyzer -	9924	6498	4726
		Compressor -	3767	1770	1507
		Other costs	8214	4961	3739
		Total costs	**21905**	**13229**	**9972**

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 [2] 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	66.5%	68.0%	75.0%	58.0%	65.5%	70.5%
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, based on [6, 8, 9]

Equipment	Share of CAPEX		
Electrolyzer size	**All size**	**1 MWel**	**10 MWel**
PEM electrolyzer	4%		
Alkaline electrolyzer	2.5%		
H2 compressor	4%		
Non-equipment	4%		
PEM electrolyzer incl. compressor and other costs		4%	4%
Alkaline electrolyzer incl. compressor and other costs		3.4%	3.3%

An expected range of lifetime of the electrolyzer today and in future is presented in [2], 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 [2]

	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

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Appendix B – Variation in electrical vehicle efficiency due to outside temperature

When simulating a large share of battery electrical vehicles (BEV's) instead of internal combustion engines (ICE) it is worth to consider their technical difference. In contrast to the ICE vehicle, the BEV's are much more energy efficient and are lacking sufficient waste heat to provide substantial cabin heating. It leads to larger fluctuation in energy demand depending on season for BEV's in comparison with an ICE vehicle.

A literature review in November 2019 identified the following references of testing BEV's during cold conditions:

Author	Year	Country	Car type	Method
AAA	2019	USA	BMW I3s Chevrolet Bolt Nissan Leaf Tesla Model S 75D Volkswagen e-Golf	Climate laboratory testing in UDDS and HWFET cycles
Zhang, et al	2017	China	Unknown	Climate laboratory and modelling of NEDC cycle
Reyes, et al	2016	Canada	Nissan Leaf Mitsubishi i-MiEV	Urban road testing until battery depletion
De Gennero, et al	2014	Austria	Unknown	Climate laboratory based on various driving cycles
Laurikko, et al	2013	Finland	Mitsubishi i-MiEV Volvo C 30 Tesla Roadster Renault Kangoo Nissan Leaf Citroen C-Zero	Modelling, laboratory and road testing in test track using various driving cycles
Borba	2012	Canada	Nissan Leaf	Data from 148 winter commute trips

The performance of a BEV can either be expressed as a driving range measured in km or energy demand measured in kWh used per km. To include BEV's in energy system modelling, such as TIMES, the performance expressed in kWh/km is of relevance. This paper is focusing in the change of performance between seasons and using the most favourable driving conditions as a base reference. Thus, the exact energy efficiency of a specific BEV or a fleet of BEV's is not discussed. The percentage change in the performance which is presented in this paper is calculated as

$$y = \left(\frac{E_1}{E_{ref}} - 1\right) \qquad \text{(B-1)}$$

where, y is the percentage increase in energy demand, E_1 is the energy demand at an altered outside temperature (and sometimes only due to AC usage) from when the energy demand was measured at lowest energy demand (E_{ref}).

Some articles are presenting the change in performance as a change in range. In this case the range is converted to energy demand by

$$E = \frac{battery_{size}}{range} \tag{B-2}$$

Where *battery*$_{size}$ in kWh and *range* is in km.
The change in energy demand can be calculated from range by

$$y = \left(\frac{\frac{battery_{size,1}}{range_1}}{\frac{battery_{size,ref}}{range_{ref}}} - 1 \right) \tag{B-3}$$

The index *ref* is referring to the conditions where the largest driving range was achieved and index *1* refers to any other operational condition. This calculation is simplified in this article by assuming a fixed battery capacity regardless of the outside temperature and equation (B-2)(B-3) can be simplified to:

$$y = \left(\frac{range_{ref}}{range_1} - 1 \right) \tag{B-4}$$

Factors which can alter energy demand in BEV's are increased air density, temperature for batteries, heating demand for the cabin and increased rolling resistance. The increased rolling resistance can be both due to usage of winter tyres and driving in snow and slush. To which extent a single factor is affecting the energy efficiency depends on the driving pattern of the vehicle. In Europe a predefined driving pattern called NEDC has typically been used to test and compare cars and their performance. It consists of 4 km urban driving pattern and 7 km highway driving pattern. However, cars can be tested in various patterns and in real life conditions, which will alter the energy consumption. [1]

The air density is increasing with 16% when temperature is decreasing from 23°C to -20°C, which in theoretical calculations increased the energy demand (kWh/km) for a small car with 6-9% depending on driving cycle. The road surface is also affecting the energy demand and a road covered with new snow can increase the energy demand with 5-7%. [2]

The energy storage capacity in a Lithium ion battery can be decreased with 20% at -20°C in comparison with +20°C [3]. In addition, the batteries lifetime can be substantially decreased if battery temperature surpasses recommended operational temperature. Due to these reasons BEV's have a battery thermal management system (BTMS), which can either be active or passive. An active BTSM is heating the batteries in cold weather operation and it could also pre-heat the battery while charging [4]. If a car has an active BTSM, it is an additional system consuming power and will further increase the energy demand of BEV during winter time.

As BEV's are highly efficient and they are lacking any notable waste heat. To ensure a pleasant cabin comfort and to provide necessary defrosting in an BEV, the energy for heating is taken directly from the battery and by that reducing its driving range. In winter operations of -20°C the cabin heating could increase the energy demand of the vehicle between 41%-64% at constant speed of 50 km/h and between 25%-45% at constant speed of 70 km/h [2].

In Figure B-1 is compiled the increased energy demand as a function of temperature from four of the studies based on empirical data. The study made by America Automobile Association (AAA) [5] and Zhang et al [6] is based on tests in climate chambers while Reyes et al [3] drove car in an urban environment with speed limits between 50-80 km/h. The study made by Laurikko et al was not included because not the same car was tested both on warm climate with heating ventilation and air conditioning system (HVAC) off and in cold climate with HVAC on, so no representative increase in energy demand could be received.

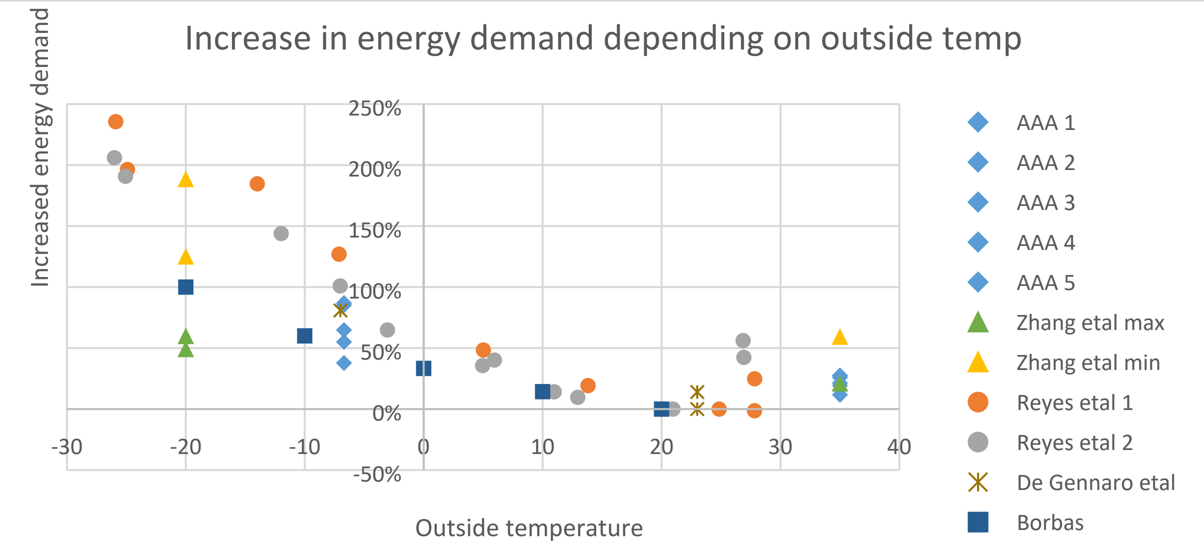

Figure B-1 A compilation of four distinct test sources, increased energy demand vs. outdoor temperature [1, 3, 5-7]

The study from AAA is the most recent study (2019) and it compares several BEV's produced in either 2018 or 2017 and a more detailed overview of the results from this study is shown in Figure B-2. During their test, the saloon heating was set in auto mode to 22°C and if possible, air recirculation option was selected. The study also analyzed energy demand with the heating turned off and the results shows that majority of increased energy demand is due to the cabin heating. In this study both BMW I3s and Nissan Leaf had both heat pumps and electric resistance heating, while the rest of cars had only electric resistance heating. As cars with heat pumps have both one of the largest and lowest increase in energy demand at -6,7°C, it shows that heat pump technology as such is not a guarantee of a better energy efficiency at cold weather. It could be explained by the low COP of heat pump at low outside temperatures and that the electrical resistance heating is the main heat source. [5]

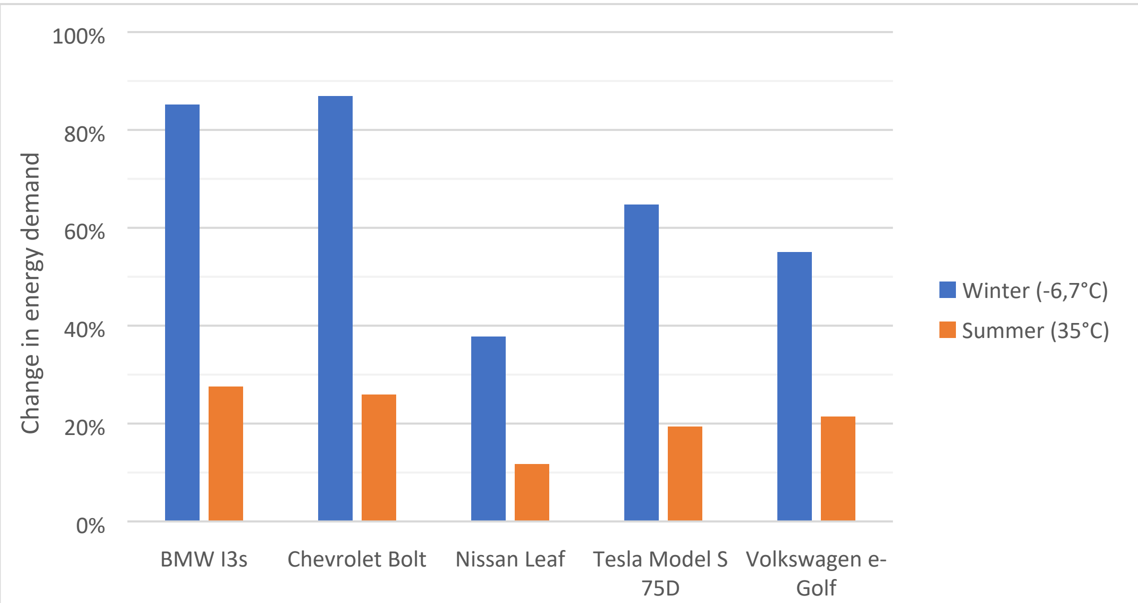

Figure B-2 Change in energy demand depending on outside conditions for various vehicles [5]

The study by Zhang et al [6] is based on testing an 3 door hatchback with 4 seats from a not revealed brand. The testing was performed at extreme temperatures in NEDC driving cycle and identifies how much the energy demand can change depending on the type of heating element and user set settings of the HVAC system. The points “Zhang etal min” in Figure B-1 shows energy demand when air is recirculated inside the cabin and the “Zhang etal max” points represents the energy demand when outside air is heated up using max level for the fan. The max and min in cold conditions has two points to illustrate possible saving using a heat pump instead of electric resistance heating.

Reyes at al [3] tested vehicle in urban environment until battery was fully depilated for a range of different temperatures for Nissan Leaf from 2012 (“Reyes etal 1” in Figure B-1) and Mitsubishi i-MiEV from 2012 (“Reyes etal 2” in Figure B-1). The Nissan was operated with HVAC set to +21°C and the Mitsubishi HVAC was adjusted to comfortable temperature hence it was missing more sophisticated control system. Both the studies of Reyes etal have the highest increase in energy demand in comparison with the other two studies. It could be explained with more realistic driving conditions, such as variating rolling resistance due to asphalt or snow conditions or difference in user pattern in comparison with NEDC or other predefined in lab driving cycles. Another factor of importance is that the study was calculating only the driving distance, which has been simplified in this article to represent increase in energy demand. However, the decrease in range can also partially be explained due to decreased energy storage capacity in battery in cold climate. A valuable conclusion that can be made from this study is that the energy demand increases relatively linear from ~20°C down to approx. -25°C.

In the three studies presented above is also shown increased energy demand at high outside temperatures due to usage of AC and for cooling of batteries if an active BTMS is present.
The experience to drive a Nissan Leaf during winter conditions as presented by Borbas [7] shows a relatively conservative increase in energy demand in comparison with the other studies. The representativeness of these data is however unclear due to two reason. Firstly the energy efficiency is based on decline in range which probably overestimates the increase in energy demand due to temperature based on the same reasons as for [3] described above. Secondly, the driver presents himself as an engaged first adopter of EVs and conscious about driving in energy efficient manner with modest cabin heating. It can be expected that an average driver would prioritize comfort and more aggressive driving more than energy efficiency and by that increase the energy demand.

Conclusions

The energy demand is increasing as outdoor temperature is decreasing and the increase can be simplified to a linear correlation.

The worst-case correlation between energy demand increase and outside temperature can be based upon the results presented by Reyes et al and are shown in Figure B-3.

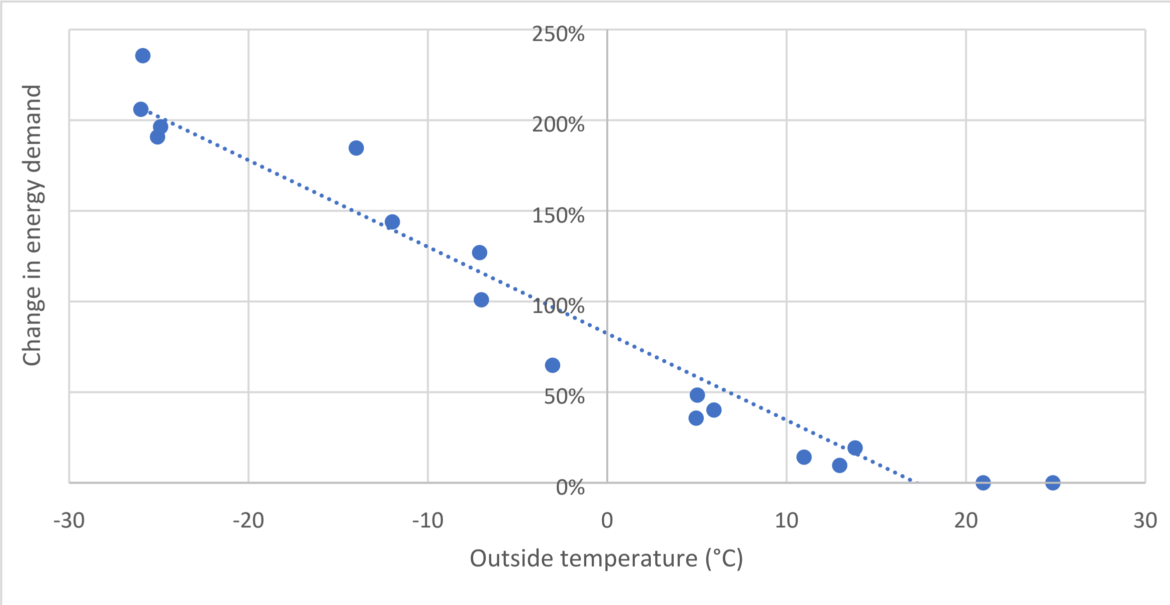

Figure B-3 Correlation made for a worst case energy demand increase based on data from [3]

The consumption from AAA is presented as a best case example due to the HVAC is set actively to recirculation mode in the test, which is not assumed to be manually set by all car users and that sometimes fresh air is required for the defrosting purpose. In addition, the test was done inside, which means that outside conditions such as increased rolling resistance due to snow and slush will probably further increase the energy demand.

To estimate a best case, basis is taken in assumed linear correlation between outside temperature and increase in energy demand and the average increase in energy demand of 66% at -6,7°C based on results from various BEV's presented in [5]. The average increase in energy demand is almost identical with the results of the Tesla S. In addition, the increase in energy demand is assumed to start at 17,2°C, the same point as for worst case correlation shown in Figure B-3. Based on the assumptions above, the correlation for best case is presented as

$$y = -0{,}0276 * T + 0{,}475 \tag{B-5}$$

where *y* is the percentage increase in energy demand and *T* is the ambient temperature in Celsius. In Figure B-4 is shown the best and worst case of increase in energy demand due to decrease in outside temperature with reference to the studies on which the conclusion has been made. It shall be noted that correlation is only applicable for outside temperature below 17,2°C.

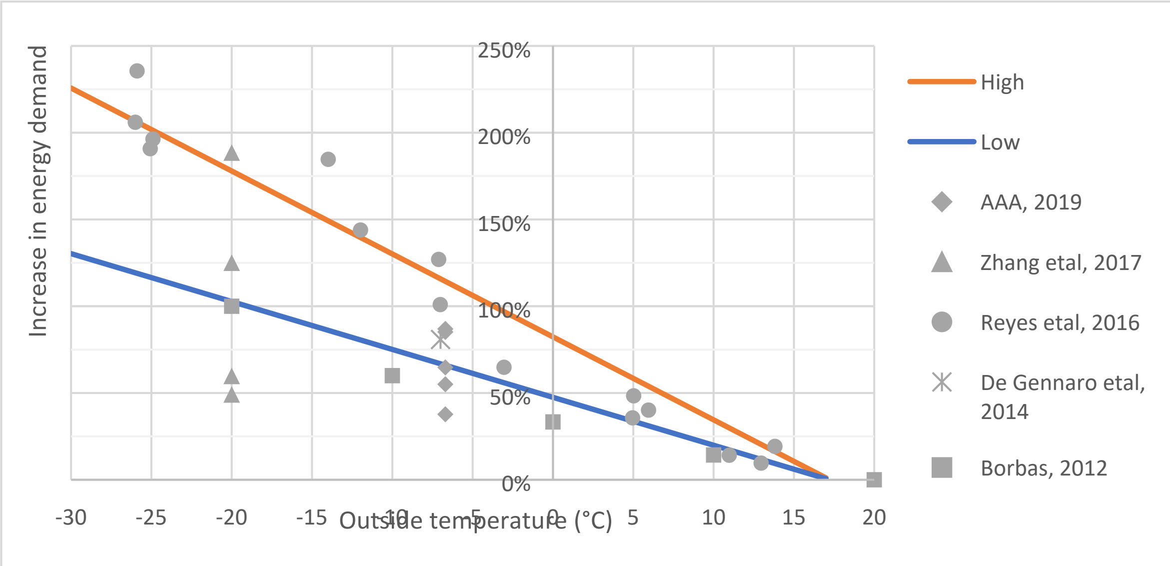

Figure B-4 Assumed span of increase in energy demand depending on outside temperature and for reference marked datapoints received from the literature.

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