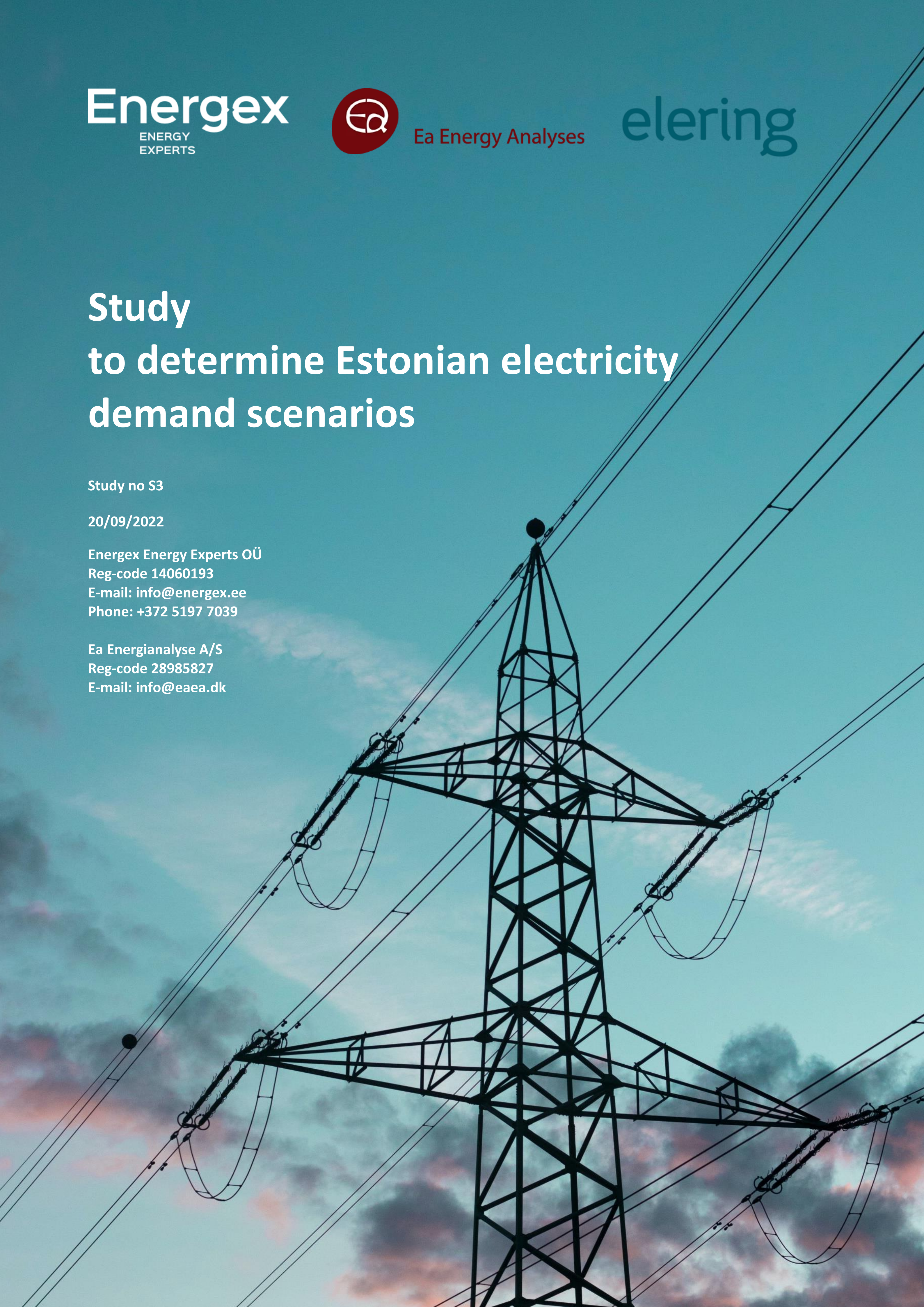
Study to determine Estonian electricity demand scenarios

Study no S3

20/09/2022

Energex Energy Experts OÜ
Reg-code 14060193
E-mail: info@energex.ee
Phone: +372 5197 7039

Ea Energianalyse A/S
Reg-code 28985827
E-mail: info@eaea.dk



Study to determine Estonian electricity demand scenarios

TABLE OF CONTENTS

BACKGROUND 3

EXECUTIVE SUMMARY 4

KOKKUVÕTE - SUMMARY IN ESTONIAN 11

1. METHODOLOGY 18

1.1. Base consumption model 19

1.2. Sector-specific models 22

2. ELECTRICITY DEMAND SCENARIOS 22

2.1. District heating 22

2.2. Natural gas electrification 24

2.3. Buildings 27

2.4. Solar power 30

2.5. Transport electrification 32

3. MODEL RESULTS 43

3.1. Model's structure 43

3.2. Aggregated results 44

4. FACTORS AFFECTING THE DEMAND 51

4.1. Demand side response potential 51

4.2. "Typical" datacentre 53

4.3. District heating heat pumps 55

4.4. District heating electric boiler combined with a heat storage 56

4.5. The building sector renovation program and energy performance 57

4.6. Home charging 59

4.7. Electric vehicle fleet 61

4.8. Grid connected and market-based battery storage 63

4.9. Grid connected and market-based power-to-gas 67

5. REFERENCES 71

ANNEX 1. ELECTRICITY CONSUMPTION PROFILES IN THE TRANSPORT SECTOR 75

ANNEX 2. BASE SCENARIO RESULTS 77

ANNEX 3. HIGH SCENARIO RESULTS 80

ANNEX 4. LOW SCENARIO RESULTS 83

ANNEX 5. HIGH SCENARIO RESULTS COMPARED TO BASE 86

ANNEX 6. LOW SCENARIO RESULTS COMPARED TO BASE 89

Background

The objective of the study is to determine Estonian electricity demand scenarios up to 2050, considering the increase of energy efficiency, economies organic growth and the electrification of fossil consumption, like transport and industry.

The study is conducted in accordance with the contract No 1.1-4/2021/689. The Employer is Elering AS and contractors are Energex Energy Experts OÜ and EA Energianalyse a/s. The work was compiled by a team of experts from Energex Energy Experts OÜ in collaboration with Energianalyse a/s.

The analysis methodology is based on the procurement conditions set out in the terms of reference. Elering provided historical hourly consumption data of 110 kV substations and is responsible for the accuracy of the source data. The study is based on EU and Estonian national climate goals, policies, proposed policies, other relevant studies, and the contractor's experience that is related to the study topic. Multiple bi-weekly conference calls and meetings were held to present the state of progress of the study and discuss the data used in the study. The work was performed in two stages. The first stage was to conduct preliminary results and the second stage was to finalize the report and the model. The preliminary results were presented on February 18, 2022. The first results were presented on May 11, 2022. The model training workshop held on June 14, 2022. Final study report and Excel model files were presented on June 27, 2022. Multiple rounds of feedback was received until final changes were completed on September 20, 2022.

The contractors are grateful and would like to say thank you to Elering AS for the valuable collaboration and contribution.

The Authors of the study: Enar Kraav, Andre Tammik, Ott Salla, Kristiina Angela Kelder, Markus Tamm (**Energex Energy Experts OÜ),** Mikael Togeby, Anders Kofoed-Wiuff (**Ea Energianalyse A/S).** Employer's representatives: Siim Iimre, Jarmo Ling, Oleg Tsernobrovkin (**Elering AS**).

About Energex Energy Experts:
Energex Energy Experts is an engineering and consulting services company specialising in energy, digitisation, production technologies and processes. The mission of Energex is to contribute to the economic, social and environmentally sustainable development of its customers.

About Ea Energy Analyses:
Ea Energy Analyses is a Danish consulting company providing consulting services and performing research in the field of energy and climate change.

Executive summary

The study determined Estonian electricity demand scenarios for household, services, industry and transportation sector up to 2050. Three electrification scenarios for all the sectors were compiled by the authors. Three scenarios of electrification are as follows: low, base, and high. Base scenario follows previously compiled studies, strategies, and roadmaps. Low and high scenarios are deviations of the base scenario. Furthermore, scenarios provide annual energy demand values and peak power values with hourly load profiles for 110 kV substations.

The result is the creation of electricity demand scenarios providing yearly energy demand values and peak power values, the sensitivity analysis of different factors affecting electricity demand, creation of hourly load profiles for 110kV substations and the providing of an assessment of potential demand side response. The electricity demand scenarios express yearly energy demand values and peak power values for the transmission grid, consumers demand considering local load management and consumers demand without considering local load management.

The electricity demand of Estonia is assessed on three levels:

- Level 1: end user demand without local generation. On this level local production (solar power generation) and vehicle to grid is not considered.
- Level 2: distribution network demand (end user demand with local generation). This level adds local generation from solar panels on buildings to reduce demand and vehicle to grid solutions.
- Level 3: transmission network demand. This level also takes into account additional electricity generation from distribution networks, so large distinct solar farms and CHPs connected to the distribution network. Power generation in the transmission system network is not in the scope of this study.

The prediction up to 2050 considers the increase of base consumption, i.e., existing consumption that is affected by factors such as economic growth, GDP change, weather, etc. The second part of the consumption consists of the electrification of different energy consumption sectors, such as electrification of transport, natural gas consumption electrification, the technical and heating systems of renovated and new buildings along with electrification of district heating networks (Figure 1). The results also consider increasing solar power production in the distribution grid which makes up most of the distributed generation.

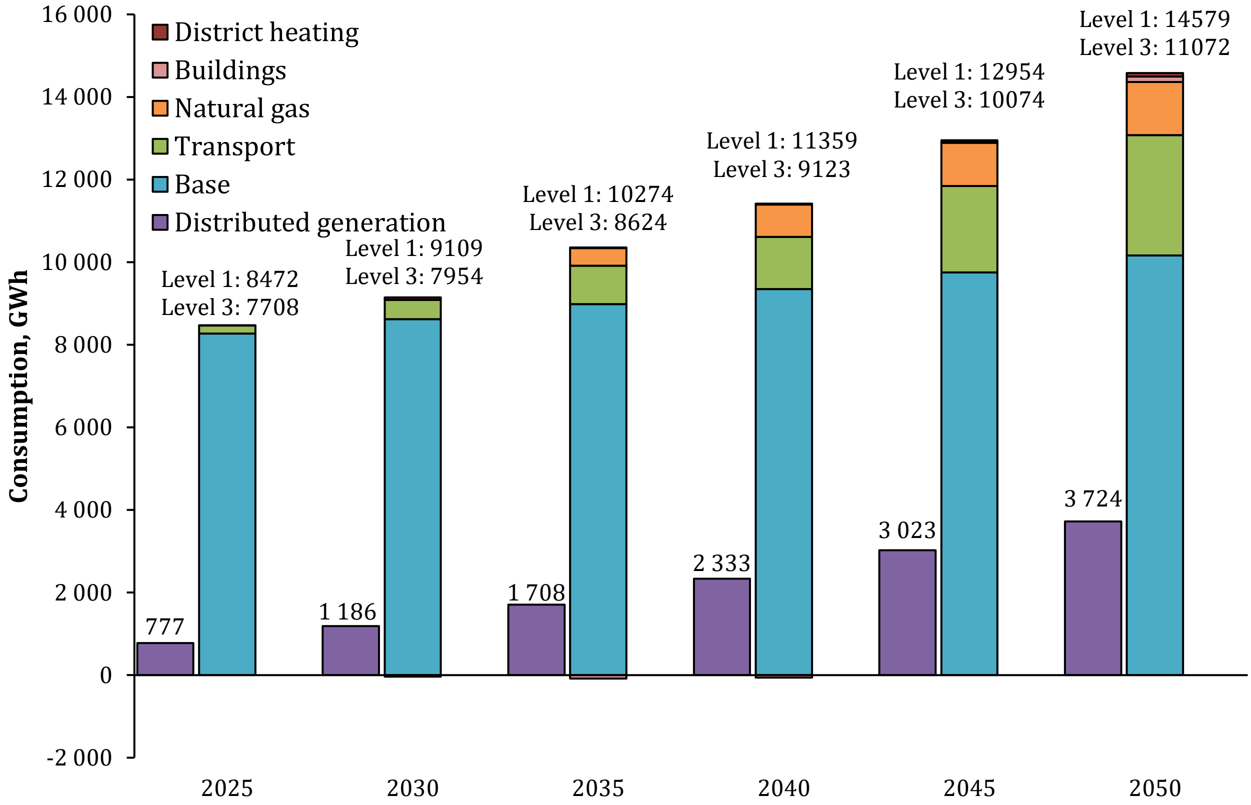


Figure 1. Average climatic year base scenario consumption

While there is an increase of electricity use in all sectors, it is expected that the transport sector will comprise around half of the increase in electricity consumption. Overall, electricity consumption is expected to be steadily increasing until 2050. As the average daily driving distance for cars is about 42 km/day (Table 1), one car on average will consume only about 10 kWh of electricity per day. So, with an 11-kW charger (which is a typical home charger power), this can be achieved within one hour. In conclusion, as in the real-world people charge their vehicles only 3-4 times per week and the required amount of electricity is not that large, it is extremely unlikely that most of EV users would regularly plug in their EVs every day at the same time and charge at the same time. Furthermore, wider prevalence of smart charging can help even further help distribute charging to take place over a longer part of the day.

Table 1. Road transport sensitivity analysis

	Cars and vans	Buses	Trucks
Vehicles, pc	10 000	100	1 000
Average distance travelled, km/y	15 383	64 958	23 306
Yearly consumption, GWh	36.5	8.9	31.8
Peak demand, MW	10.1	2.2	9.6
Lowest demand, MW	1.1	0.3	0.4

Although energy efficiency is constantly increasing, which does reduce energy consumption in some respects, the effects of economic growth and the electrification of large sectors of energy consumption on electricity consumption is much greater, which is projected to increase electricity demand greatly in the coming years. However, even solar power generation in the distribution grid can cover a large part of the increase. As solar power is cyclical during the day, it will encourage the introduction of electricity storage technologies like batteries, power to hydrogen and vehicle-to-grid solutions for electric vehicles or the use of electric boilers in district heating networks.

The following graphs (Figure 2-3) describe Level 1 overall peak hourly demand and peak demand in summer during extreme climate years (ECY) from 2025 to 2050. Figure 4 and Figure 5 describe Level 3 peak demand during extreme climatic years. The ECY used in the graphs has a cold winter and a cold summer. The figures include demand projections for the base scenario, low scenario, and high scenario. Peak energy consumption is likely to rise consistently during the years and in summer and winter. The actual transmission network demand (Level 3) is likely to be lower than end user demand (Level 1), if there is available production (e.g. solar panels) or storage capacity (that can shift the demand) on the end consumers' side or in the distribution network. As peak demand is expected to nearly double during the considered time series, it is going to be an important consideration for electricity grid operators in the future.

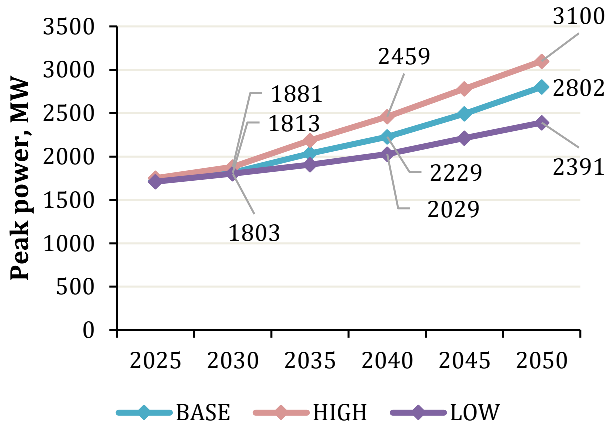


Figure 2. Level 1 ECY hourly peak power

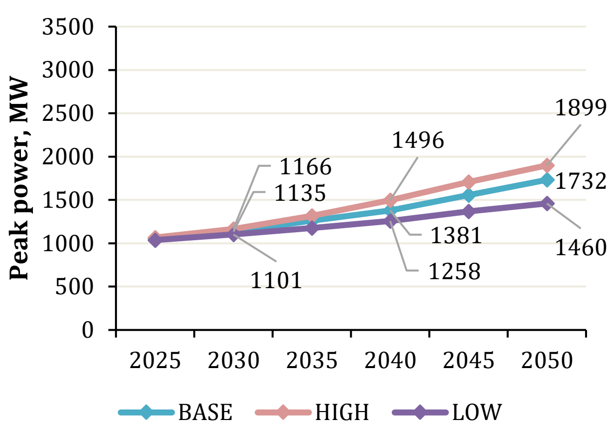


Figure 3. Level 1 ECY summer hourly peak power

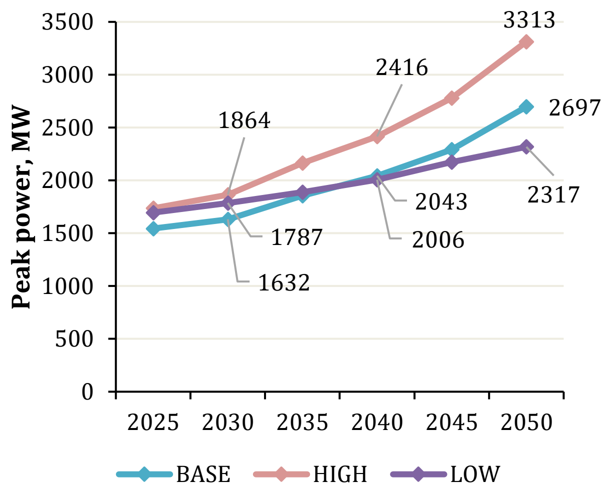


Figure 4. Level 3 ECY hourly peak power

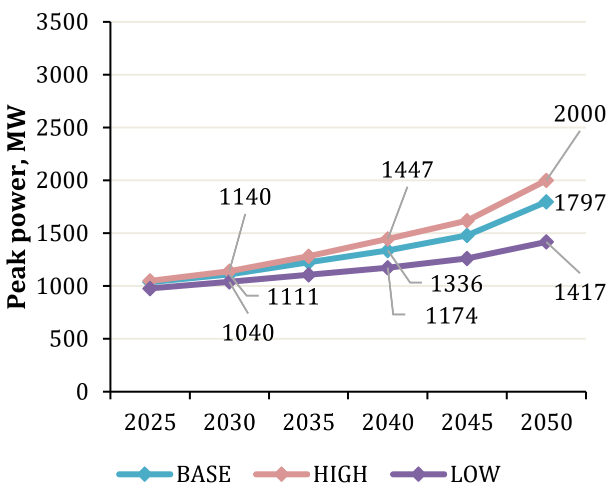


Figure 5. Level 3 ECY summer hourly peak power

Comparing the average summer weekday consumptions for level 1 and level 3 average climatic year, the distribution of the PV generation becomes apparent: the overall energy consumption rises and the daily extremes will increase (Figure 6 and Figure 7). During daytime, the PV panels output more energy than can be immediately consumed, which will encourage the introduction of electricity storage technologies like batteries, power to hydrogen and vehicle-to-grid solutions for electric vehicles or the use of electric boilers in district heating networks. This in turn will help to stabilize prices on electricity markets. A large contributor to increased peaks during evening and night are electric vehicles, which are likely to charge during that period.

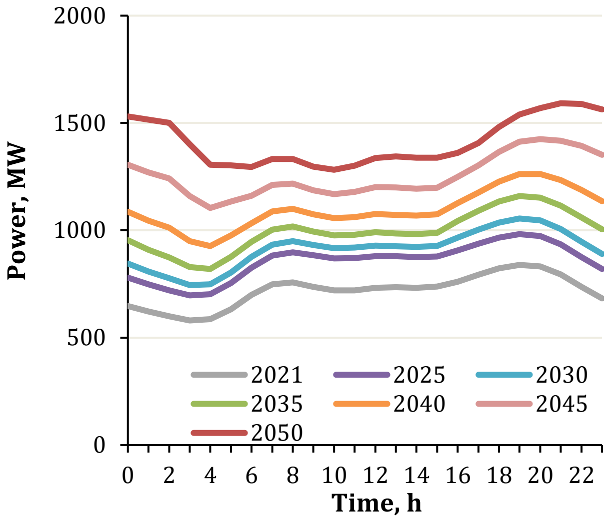


Figure 6. Level 1 ACY base summer weekday

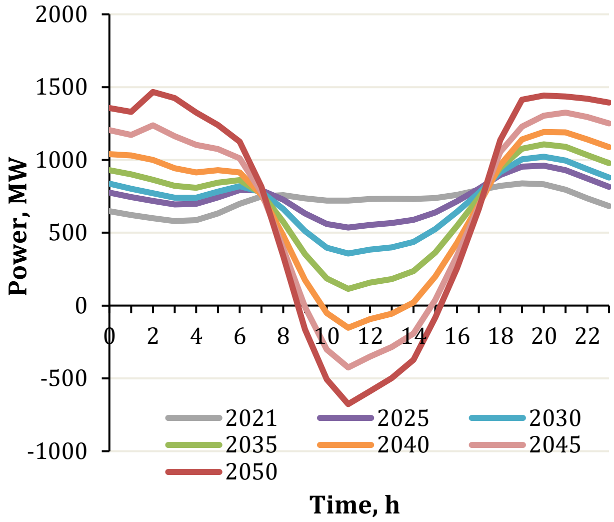


Figure 7. Level 3 ACY base summer weekday

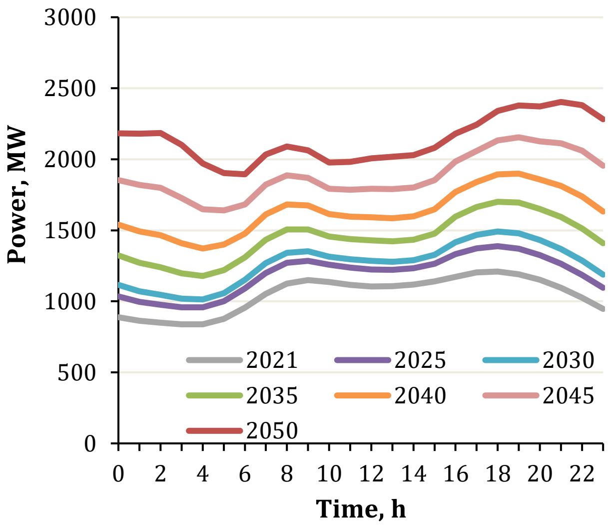


Figure 8. Level 1 ACY base winter weekday

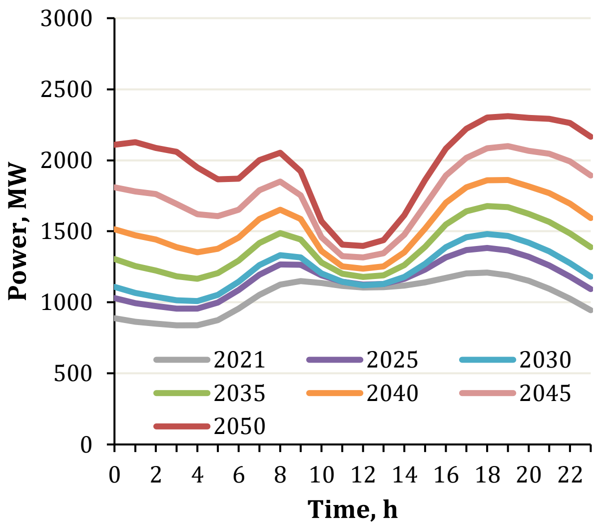


Figure 9. Level 3 ACY base winter weekday

Figure 8 and Figure 9 show that the consumption will be higher in winter and increase steadily till the studied period of 2050. In the winter, solar panels will produce less energy than in the summer due to the reduced amount of sunlight available, which results in a more stable power consumption profile during the winter months.

Figure 10 describes the assumptions made for the electrification level of smaller district heating networks, i.e., networks with a yearly consumption under 16 GWh. Figure 11 describes assumptions made for the electrification level of natural gas use in Estonia.

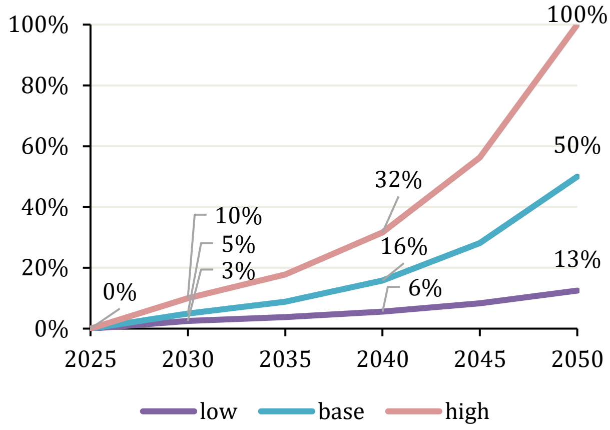


Figure 10. Electrification of smaller district heating networks

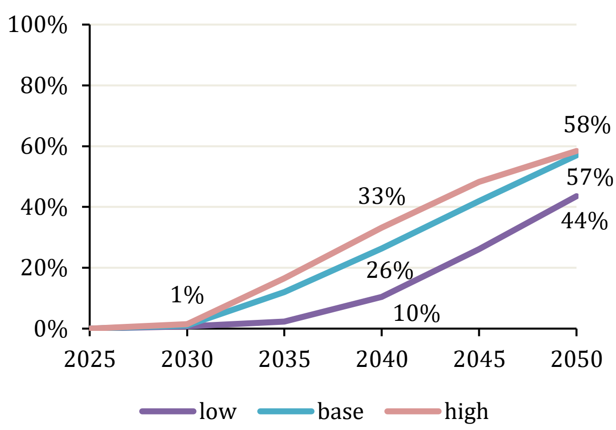


Figure 11. Electrification of natural gas consumption

Figure 12 shows the level of renovated buildings during the considered time-series, the main difference between scenarios is in the rate of renovation during the years, the final share of 2050 is identical. To estimate the building renovation effect on electricity consumption, the model is based on the long-term strategy for building renovation [1]. The main goal of the strategy is to fully reconstruct all buildings, that were built before the year 2000, by the year 2050. Figure 13 shows the projected rooftop solar panel capacity, which results from the renovation of buildings and is a conservative assessment.

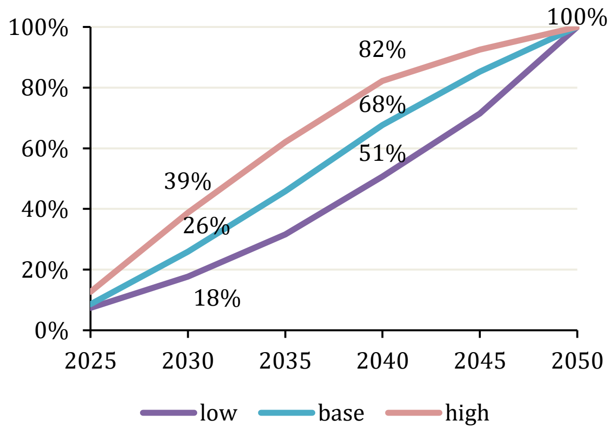


Figure 12. Level of building renovation

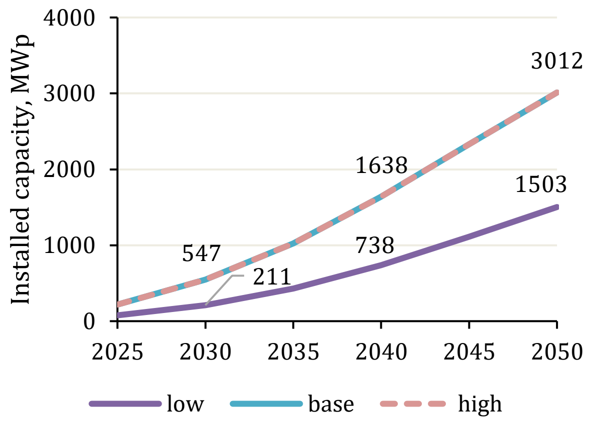
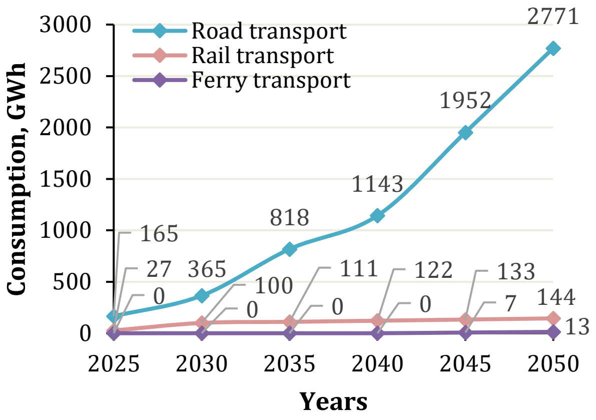


Figure 13. Installed rooftop solar panel capacity

The assumed number of electric vehicles during the time-series can be found in Table 2. The number of electric vehicles is set to increase rapidly with about 80 000 cars and vans on the roads by 2030. Figure 14 and Figure 15 describe the effect of transport sector electrification on overall yearly electricity demand and peak consumption. Clearly, road transport is going to have the most significant effect on the electricity grid. The effect of further electrification of rail and ferry sectors has a much smaller effect on overall consumption, at least given the assumptions specified in this study.

Table 2. Number of electric vehicles

pcs\year	2030	2040	2050
Electric Cars and Vans	82 273	253 048	666 898
Electric Buses	262	1 208	2 231
Electric Trucks	1 282	5 495	11 256
Electric Motorcycles	8 184	25 172	66 339



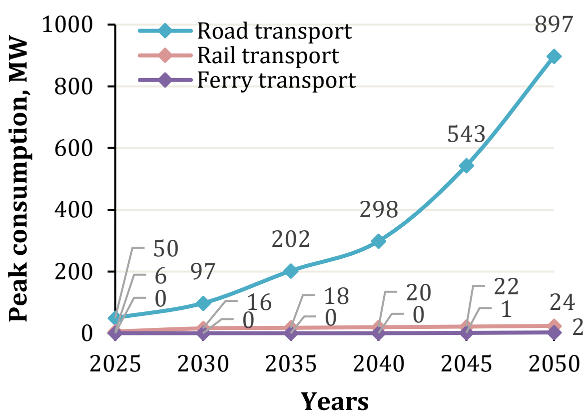
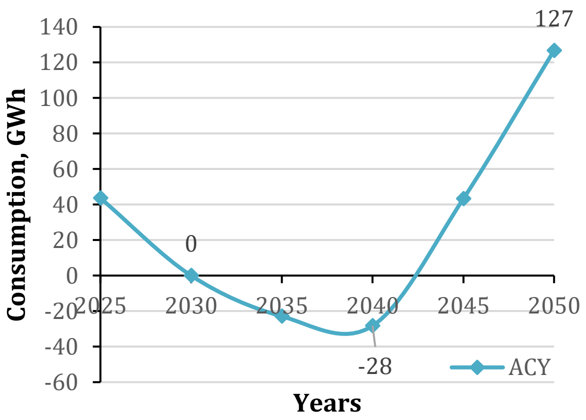


Figure 14. Electricity demand of the transport sector (base scenario, with V2G)

Figure 15. Peak consumption of the transport sector (base scenario, with V2G)

Figure 16 and Figure 17 describe the effect of building renovations on yearly electricity demand and peak consumption in the base scenario on an average climatic year. Overall electricity consumption in the sector shall increase as new technical systems that consume electricity, are introduced in the buildings, but more importantly, heating consumption of buildings shall be more electrified in the future.



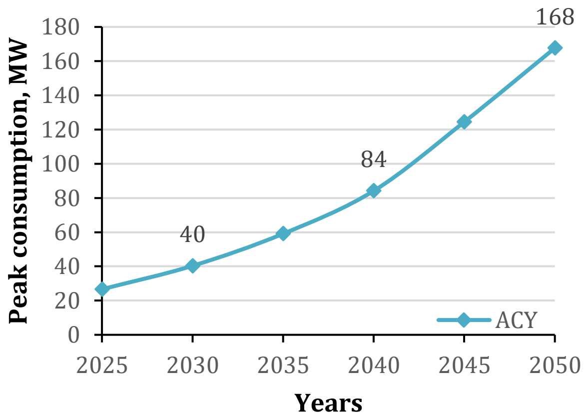
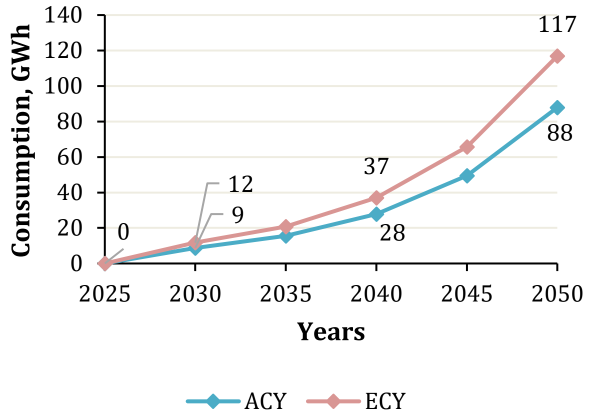


Figure 16. Buildings electricity consumption (base scenario)

Figure 17. Building peak consumption (base scenario)

Figure 18 and Figure 19 describe electrification (with heat pumps) of small (<16 GWh heat consumption) district heating networks during average and extreme climatic years (in the base scenario). Although the effect of district heating network electrification on overall demand is smaller compared to, for example, the effect of the electrification of the transport sector, the peak power of smaller networks is expected to be around 100 MW.



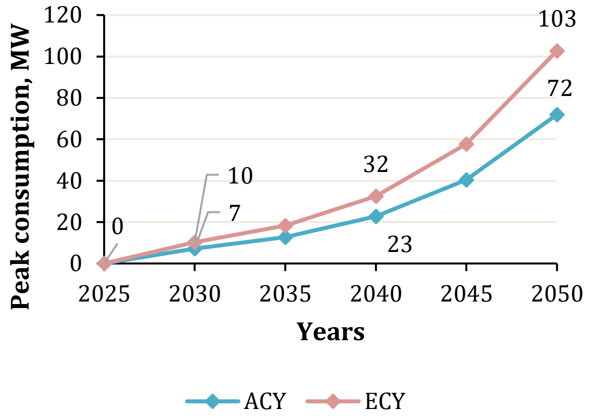
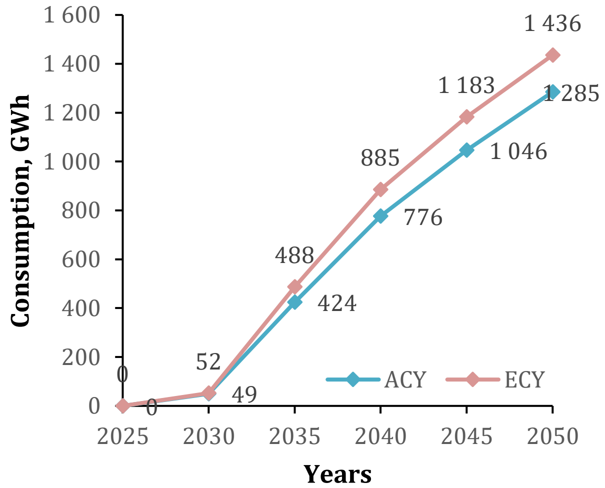


Figure 18. DH electrification electricity consumption

Figure 19. DH electrification electricity peak consumption

Figure 20 and Figure 21 describe electricity consumption and peak power demands in the base scenario (average and extreme climatic years) arising from the electrification of natural gas consumption. Electrification in this field has a higher effect on overall demand than the electrification of rural district heating networks. While yearly demand is similar for different climatic years, peak power varies significantly between them.



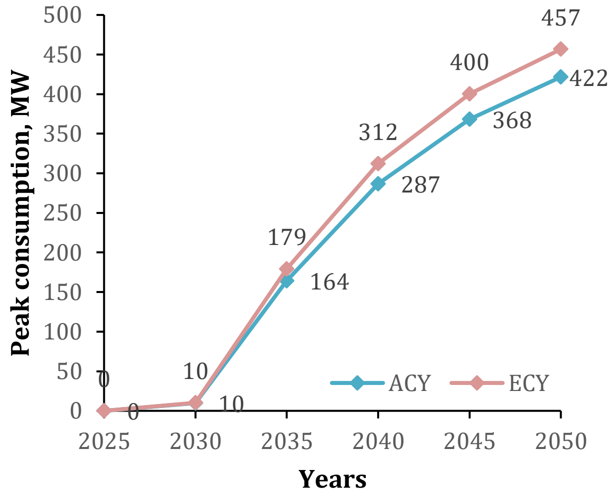


Figure 20. Natural gas electrification consumption (base scenario)

Figure 21. Natural gas electrification peak consumption (base scenario)

Kokkuvõte - Summary in Estonian

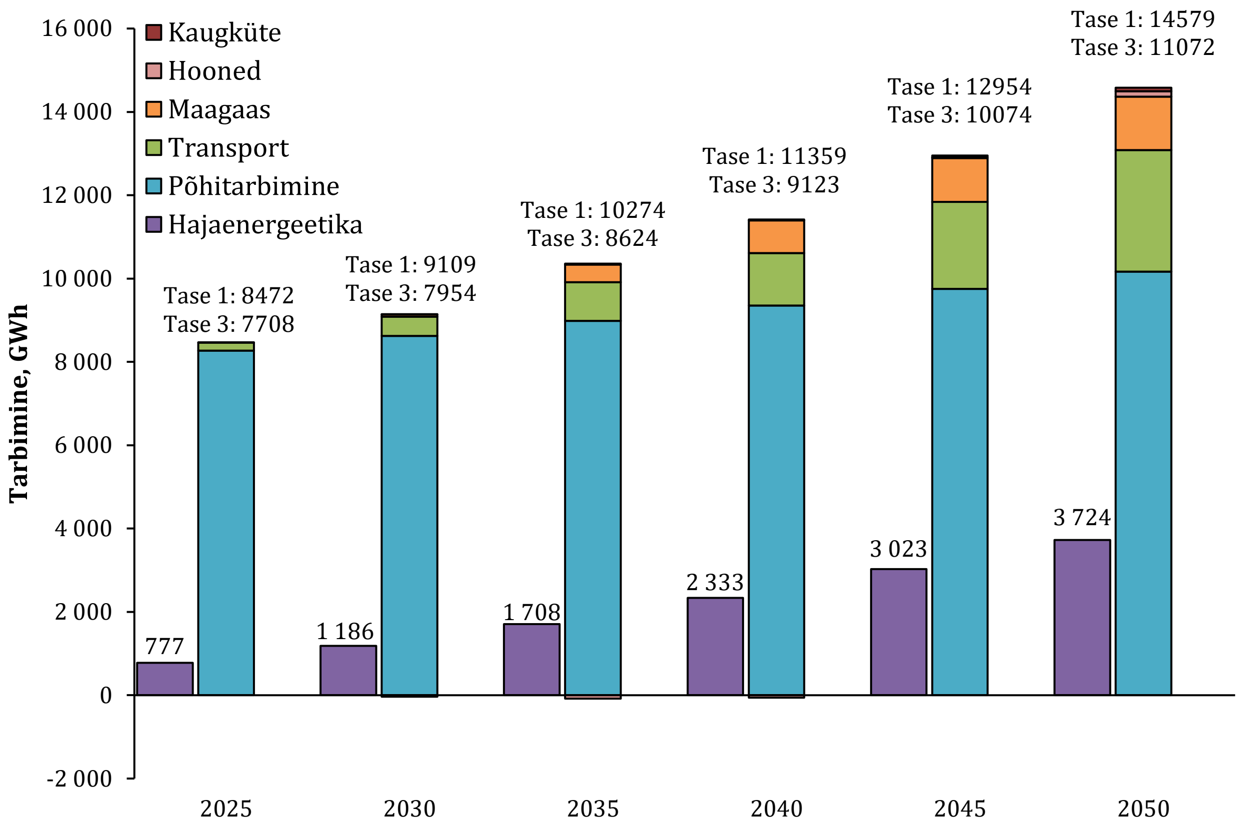
Käesoleva uuringuga leiti elektri nõudluse stsenaariumid kadumajapidamiste, teenindus-, tööstus- ja transpordisektori jaoks kuni aastani 2050, võttes arvesse energiaefektiivsuse kasvu, majanduse orgaanilist kasvu, fossiilse energiatarbimise elektrifitseerimist transpordi- ja tööstussektoris. Analüüsis kasutati sisend Eleringi 110kV alajaamade 2021 tarbimisandmeid ja prognoositud tarbimine ei sisalda ülekandevõrgu kadusid. Kõikide elektri tarbimise sektorite jaoks loodi autorite poolt kolm erinevat stsenaariumi. Need stsenaariumid on madal (*low*), baas (*base*) ja kõrge (*high*). Baasstsenaariumis järgitakse eeldustena Eestis ja Euroopas varasemalt koostatud uuringuid, strateegiaid ning teekaarte. Madalas ja kõrges stsenaarium on eeldusi muudetud vastavalt madalama ja kõrgema elektrinõudluse suunas. Stsenaariumite tulemusena hinnati aastase perioodi kogunõudlust ning tipptarbimisi. Lisaks koostati tunnitäpsusega võimsusprofiilid 110 kV alajaamadele.

Töö tulemuseks on elektri nõudluse stsenaariumid, mis kirjeldavad elektri aastast nõudlust ja tipptarbimist, tundlikkusanalüüs erinevate tarbimist mõjutavate tegurite kohta, 110 kV alajaamadele tunnitäpsusega võimsusprofiilid ning tarbimise juhtimise potentsiaali hinnang. Elektri tarbimise stsenaariumid väljendavad elektri nõudlust ülekandevõrgust, lõpptarbijate nõudlust koos jaotusvõrgus aset leidva tootmisega ning lõpptarbijate nõudlust ilma jaotusvõrgus aset leidva tootmiseta.

Eesti elektrinõudlust hinnatakse kolmel tasemel:

- Tase 1: lõpptarbijate elektrinõudlus ilma jaotusvõrgu tootmiseta. Sellel tasemel kohalikku tootmist (peamiselt jaotusvõrku ühendatud päikesepaneelid) ning elektrisõidukitest võrku andmist (edaspidi V2G – *vehicle-to-grid*) ei arvestata.
- Tase 2: lõpptarbijate nõudlus koos kohaliku tootmisega. Sellel tasemel lisatakse kohalik (hoonetel) päikesepaneelide toodang ning V2G tehnoloogiate mõju.
- Tase 3: nõudlus ülekandevõrgust. Sellel tasemel võetakse arvesse lisaks kohalikele (hoonete päikesepaneelid ja V2G) arvesse ka suuremad jaotusvõrgus asuvad tootmisvõimsused, s.o. suuremad päikesepargid ja jaotusvõrgus olevad koostootmisjaamad. Elektri tootmine ülekandevõrgus on selle uuringu ulatusest väljas.

2050. aastani loodud prognoos koosneb kahest osast. Üks neist, nii-öelda baasosa, arvestab baastarbimise kasvu, s.o olemasolev tarbimine, mida mõjutavad erinevad tegurid nagu majanduskasv, SKP muutus, ilm jne. Teine osa prognoosist koosneb erinevatest uutest elektritarbimise sektoritest nagu transpordisektori elektrifitseerimine, maagaasi tarbimise asendamine elektri tarbimisega, rekonstrueeritud ja uute hoonete muutuv elektritarbimine tulenevalt uutest tehnosüsteemidest ja hoonete energiatõhususe muutumisest ning väiksemate kaugküttevõrkude elektrifitseerimisest. Tulemustes arvestatakse ka kasvavat päikeseenergia toodangut, mis leiab aset nii suuremates päikeseparkides kui ka hoonete juures. Päikesepaneelide toodang moodustab suurima osa jaotusvõrgus aset leidvast elektritoodangust (Joonis 1).



Joonis 1. Keskmiste ilmastikutingimustega aasta summaarne tarbimine baasstsenaariumis

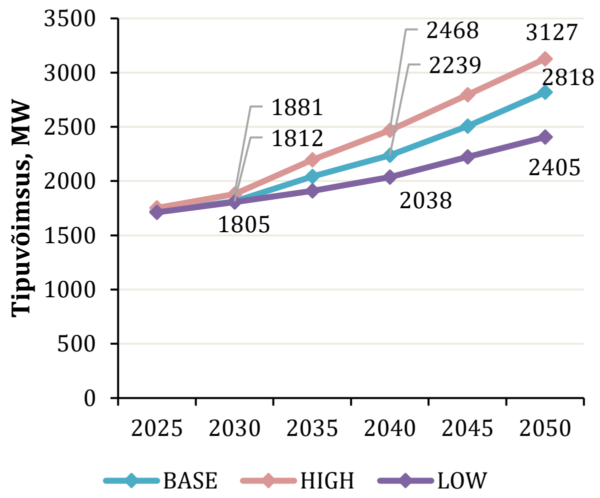
Kuigi tulenevalt kiirenevast elektrifitseerimisest leiab aset elektritarbimise kasv kõikides uuringus vaadeldud sektorites, siis transpordisektori elektritarbimise kasv moodustab orienteeruvalt poole kogu elektritarbimise kasvust 2050. aasta perspektiivis. Kuna autode keskmine päevas läbitud distants on 42 km (Tabel 1), siis on ühe elektriauto laadimisvajadus päevas ainult orienteeruvalt 10 kWh elektrit. Seega, 11 kW võimsusega laadijaga (tüüpiline kodulaadija võimsus), kulub tavapärasel päeval ühel autol keskmiselt laadimiseks ainult üks tund. Kokkuvõtteks, kuna uuringute põhjal laevad inimesed oma elektrisõidukeid ainult 3-4 korda nädalas ja päevane elektrivajadus ei ole väga suur, siis on ebatõenäoline, et kõik või enamik elektrisõidukite omanikke ühendaks oma autod võrguga täpselt samal ajal ja laeks neid samaaegselt, mis kõik vähendab ühel ajahetkel võrgust tarbitava elektri kogust. Täiendavalt, mida laiemalt levivad targa laadimise tehnoloogiad, seda rohkem jaotub elektri tarbimine nädalapäevade ja päeva tundide vahel ühtlasemalt.

Tabel 1. Maanteetranspordi tundlikkusanalüüs

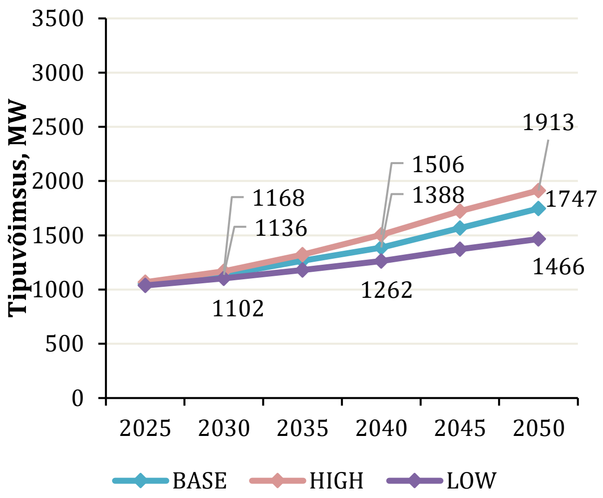
	Autod ja kaubikud	Bussid	Veokid
Sõidukite arv, tk	10 000	100	1 000
Keskmine aastane läbisõit, km	15 383	64 958	23 306
Aastane tarbimine, GWh	36.5	8.9	31.8
Tiputarbimine, MW	10.1	2.2	9.6
Madalaim tunnitarbimine, MW	1.1	0.3	0.4

Kuigi hoonete ja seadmete energiatõhusus on pidevalt kasvamas, mis vähendab teatud oludes energia tarbimist, siis majanduskasvu ja suure energiatarbimisega sektorite elektrifitseerimise mõju on oluliselt suurem, mille tõttu on summaarselt tulevate aastate jooksul elektri tarbimine märkimisväärses kasvutrendis. Näiteks, hooned muutuvad küll tulevikus energiatõhusamaks, mille tulemusel väheneb selles sektoris kütuste tarbimine hoonete kütteks, kuid kuna aina rohkem paigaldatakse elektrit tarbivaid tehnosüsteeme ning kasvab soojuspumpade kasutus, siis elektri tarbimine hoopis kasvab. Ent isegi jaotusvõrgus toimuv päikeseenergia tootmine võib suure osa sellest tarbimisest ära katta. Kuna päikeseenergia tootmine on olemuslikult päeva jooksul tsükliline, siis see stimuleerib tulevikus salvestustehnoloogiate kasutuselevõttu. Sellisteks tehnoloogiateks võivad olla näiteks akud, vesiniku elektrolüüs, V2G või elektrikatelde kasutamine kaugküttevõrkudes.

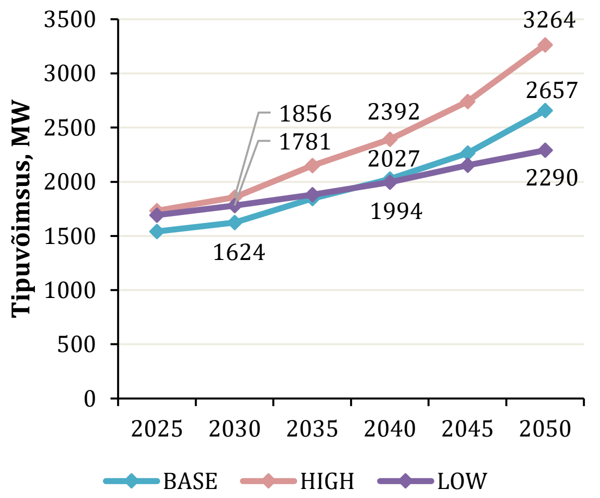
Tulevatel aastatel on oodata tiputarbimiste järkjärgulist kasvu, järgnevatel joonistel on kujutatud Tase 1 ehk lõpptarbijate maksimaalset nõudlust suvel erakordsete ilmastikutingimustega aastate korral (ECY). Järgnevad joonised (Joonis 2-3) kirjeldavad Tase 3 ehk ülekandevõrgu tarbimist samasuguste ilmastikutingimustega aastate korral. Joonistel 4-5 kasutatud ECY on külma talve ja külma suvega aasta. Joonistelt võib näha, et tegelik tarbimine ülekandevõrgust on tõenäoliselt märkimisväärselt madalam, kui lõpptarbimine, kuna tõenäoliselt paigaldatakse tulevikus märkimisväärses mahus kohalikku tootmisvõimsust (nagu päikesepaneelid) ning salvestussüsteeme. On oluline siiski märkida, et tiputarbimise osas esineb suur määramatus, sest täna ei ole teada, millises mahus salvestustehnoloogiaid ning tarbimise juhtimist kasutusele võetakse ning teiseks, praktikas juhitakse selliseid süsteeme vastavalt elektrituru hindadele, mitte vastavalt süsteemi tarbimismahtudele.



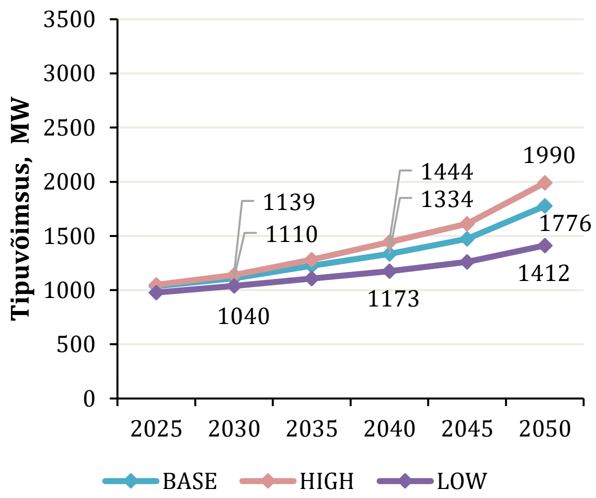
Joonis 2. Tase 1 ECY tiputarbimine



Joonis 3. Tase 1 ECY suvine tiputarbimine

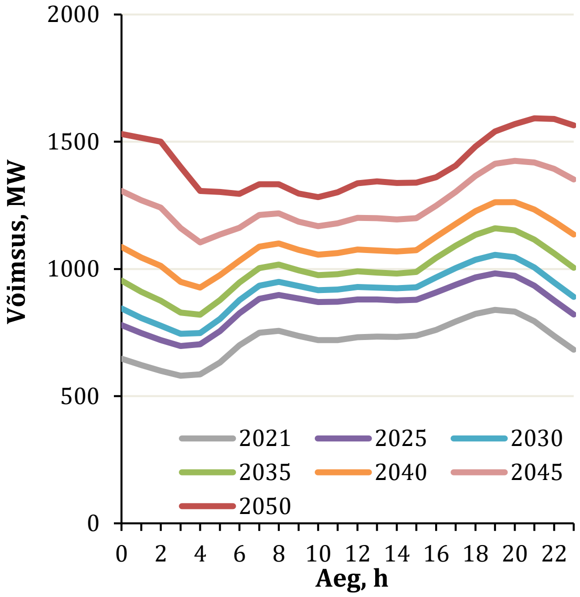


Joonis 4. Tase 3 ECY tiputarbimine

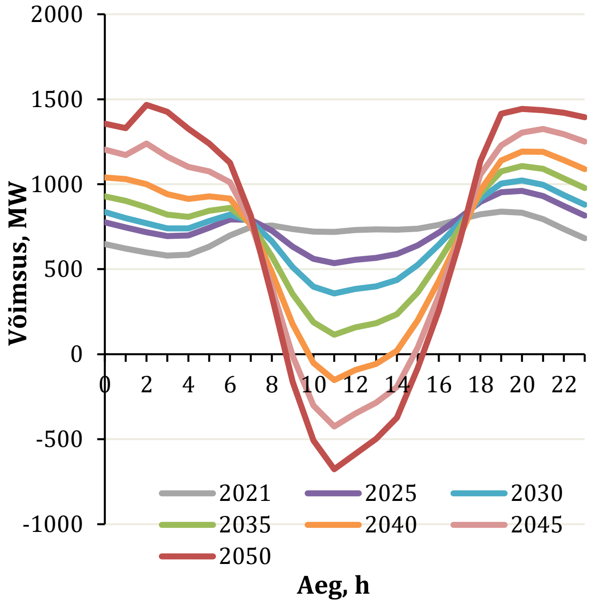


Joonis 5. Tase 3 ECY suvine tiputarbimine

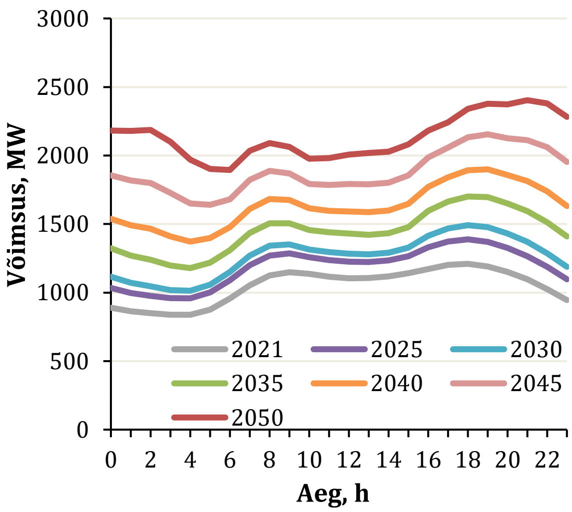
Võrreldes Tase 1 ja Tase 3 keskmist suvist töönädala tarbimist keskmise ilmastikutingimustega aastal, paistab selgelt välja päikeseenergia tootmise suur mõju järgnevatel aastakümnetel. Lisaks on näha kuidas elektri tarbimine kasvab ning ka päevased maksimumid kasvavad (Joonis 6-7). Päevasel ajal toodavad päikesepaneelid rohkem elektrit, kui tarbijad suudavad ära tarbida, mis tõenäoliselt julgustab erinevate salvestustehnoloogiate kasutuselevõttu. Suur mõju eriti õhtusele ja öisele elektritarbimise kasvule võib olla elektriautodel, sest on tõenäoline, et suur osa neist laeb sellel ajal. Suur elektri nõudluse ja pakkumise varieeruvus päeva jooksul võib põhjustada suuri elektrihinna kõikumisi. Salvestustehnoloogiate kasutuselevõtmine saab aga aidata elektri tarbimisprofiili stabiliseerida ning läbi selle ka hindu stabiliseerida.



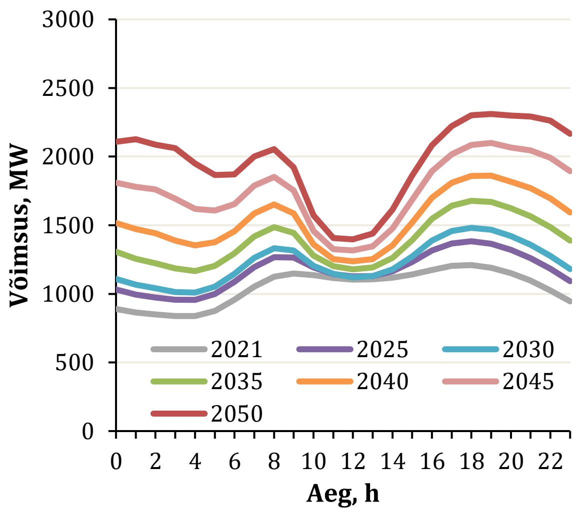
Joonis 6. Tase 1 ACY suvine tööpäev, baasstsenaarium



Joonis 7. Tase 3 ACY suvine tööpäev, baasstsenaarium



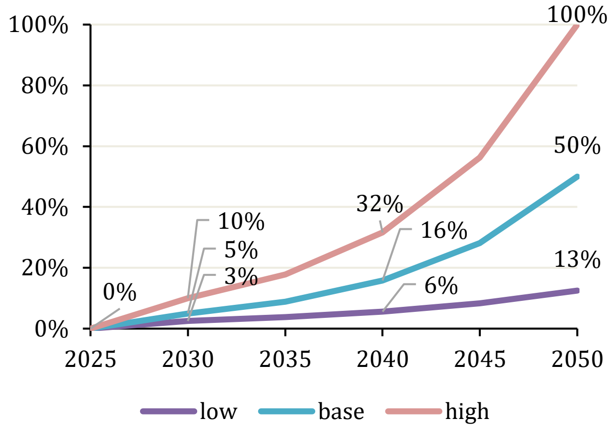
Joonis 8. Tase 1 talvine tööpäev, baasstsenaarium



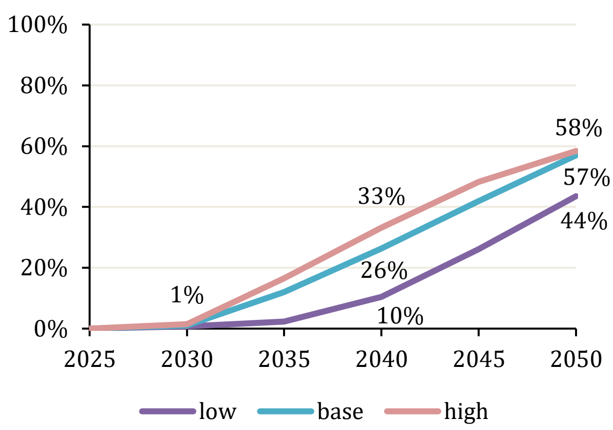
Joonis 9. Tase 3 talvine tööpäev, baasstsenaarium

Joonistelt 8 ja 9 on näha, et ka talvel kasvab vaadeldud perioodil tarbimine. Kuna talvel toodavad päikesepaneelid vähem elektrit, siis on talvisel perioodil tarbimisprofiil oluliselt stabiilsem ning kogu jaotusvõrgus päikesepaneelide poolt toodetud energia suudetakse kohe ära tarbida.

Joonis 10 kirjeldab väiksemate kaugküttevõrkude elektrifitseerimise taset (võrgud, mille aastane tarbimine on alla 16 GWh). Joonis kirjeldab elektrifitseeritava tarbimise osakaalu. Joonis 11 näitab maagaasi tarbimise elektrifitseerimise prognoosi tegemiseks tehtud eeldusi. Joonis kirjeldab maagaasi osakaalu, mis elektrifitseerimisel asendub elektri tarbimisega.

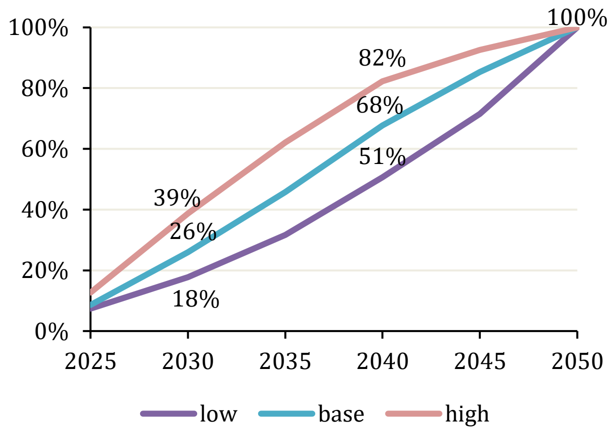


Joonis 10. <16 GWh tarbimisega kaugküttevõrkude elektrifitseerimine

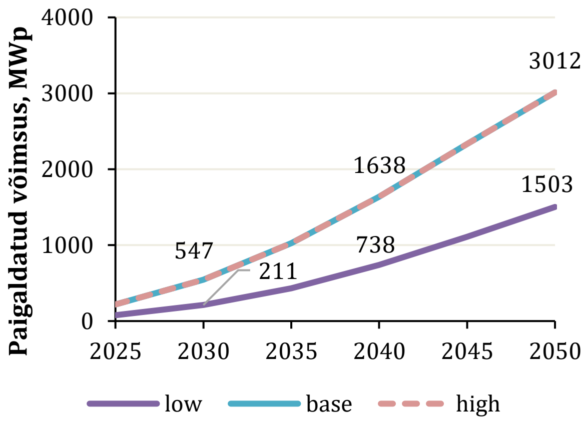


Joonis 11. Maagaasi tarbimise elektrifitseerimine

Joonis 12 näitab vaadeldud perioodi jooksul renoveeritavate hoonete hulka. Stsenaariumite peamine erinevus on muutuse kiiruses perioodi jooksul. Lõpuks saavutatakse sama renoveerimise tase. Hindamaks hoonete renoveerimise mõju elektritarbimisele, on hoonete mudel üles ehitatud vastavalt Hoonete rekonstrueerimise pikaajalise strateegia eesmärkidele [1]. Selle strateegia peamine eesmärk on kõikide enne 2000 aastat ehitatud hoonete rekonstrueerimine. Joonis 13 näitab eeldatud hoonete päikesepaneelide mahtu aastani 2050. Tegemist on konservatiivse eeldusega, mis tuleneb hoonete renoveerimise prognoosist.



Joonis 12. Renoveeritud hooned

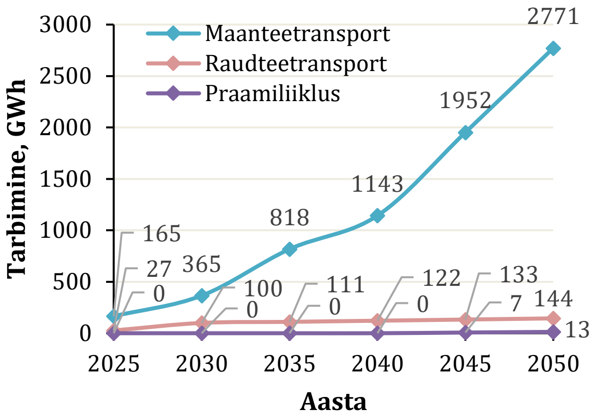


Joonis 13. Katustele paigaldatud PV paneelide võimsus

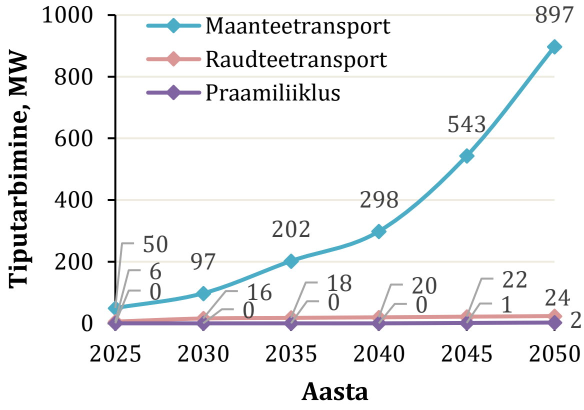
Elektrisõidukite arvu prognoos on näidatud Tabelis 2. Elektriautode arv kasvab tõenäoliselt kiirelt ületades aastaks 2030 80 000 sõiduki piiri. Joonised 14 ja 15 kirjeldavad transpordisektori elektrifitseerimise mõju aastasele elektritarbele ning tiputarbimisele. Selgelt on maanteetranspordi mõju võrreldes teste alasektoritega suurim. Praamiliikluse ja raudteetranspordi elektrifitseerimise mõju on oluliselt väiksem.

Tabel 2. Elektrisõidukite arv

tk/aastas	2030	2040	2050
Electrilised autod ja kaubikud	82 273	253 048	666 898
Elektrilised bussid	262	1 208	2 231
Elektrilised veokid	1 282	5 495	11 256
Elektrilised mootorrattad	8 184	25 172	66 339

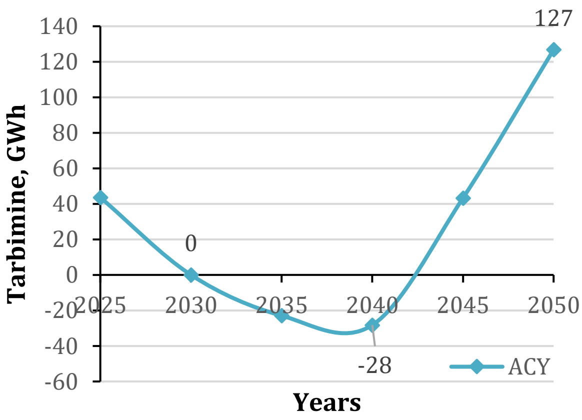


Joonis 14. Transpordisektori elektritarbimine

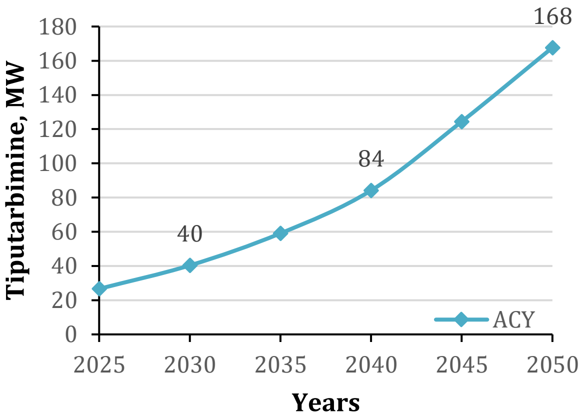


Joonis 15. Transpordisektori tiputarbimine

Joonised 16 ja 17 kirjeldavad hoonete renoveerimise mõju elektri tarbimisele ja tiputarbimisele baaasstsenaariumis keskmiste ilmastikutingimustega aastal. Elektritarbimine selles sektoris üldjoontes kasvab tulenevalt uutest tehnosüsteemidest, kuid ka hoonete kütte elektrifitseerimise tõttu.

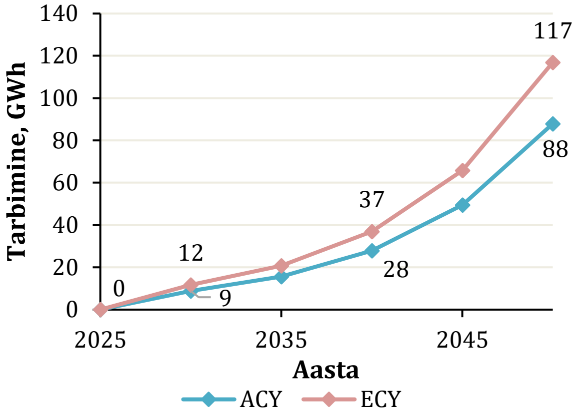


Joonis 16. Hoonete elektritarbimine

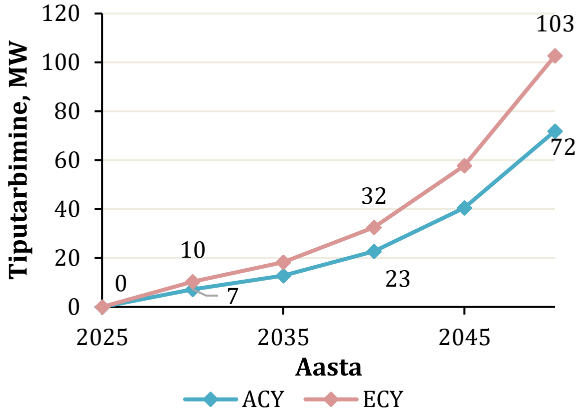


Joonis 17. Hoonete tiputarbimine

Joonised 18 ja 19 kirjeldavad väikeste kaugküttevõrkude elektrifitseerimisest tulenevat elektritarbimise ja tiputarbimise kasvu keskmiste ilmastikutingimustega aastate ja ebatavliste ilmastikutingimustega aastate korral (baasstsenaariumis). Kuigi kaugküttevõrkude elektrifitseerimise mõju on võrreldes nt transpordisektoriga väike, siis kaugküttevõrkude tiputarbimine prognoositakse olema ligikaudu 100 MW

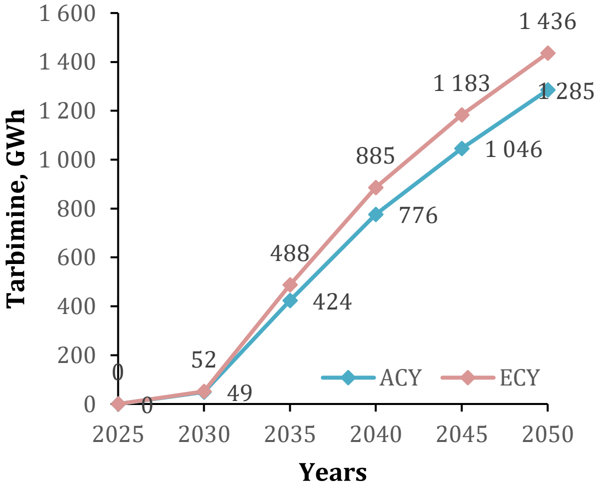


Joonis 18. Kaugkütte elektrifitseerimise elektri tarbimine

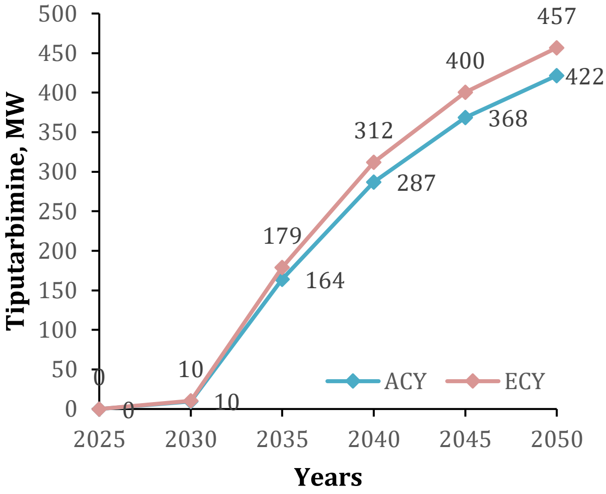


Joonis 19. Kaugkütte elektrifitseerimise tiputarbimine

Joonistel 20 ja 21 kirjeldatakse maagaasi tarbimise elektrifitseerimise mõju elektri tarbimisele ja tiputarbimisele. Maagaasi tarbimise elektrifitseerimisel on suurem mõju kogu nõudlusele, kui väiksemate kaugküttevõrkude elektrifitseerimisel. Erinevate ilmastikutingimustega aastatel on tarbitava elektri kogus sarnane, kuid nende tiputarbimised erinevad märgatavalt.



Joonis 20. Maagaasi kasutuse elektrifitseerimise tarbimine, baasstsenaarium



Joonis 21. Maagaasi kasutuse elektrifitseerimise tiputarbimine, baasstsenaarium

1. Methodology

Climate change and environmental degradation are an existential threat to Europe and the world. To overcome these challenges, the EU has agreed on the European Green Deal, which will transform the EU into a modern, resource-efficient, and competitive economy, ensuring no net emissions of greenhouse gases by 2050 and economic growth decoupled from resource use. [2]

As an intermediate step towards climate neutrality, the EU has raised its 2030 climate ambition, committing to cutting emissions by at least 55% by 2030. The EU is working on the revision of its climate, energy and transport-related legislation under the so-called 'Fit for 55 package' in order to align current laws with the 2030 and 2050 ambitions [3]. Estonia is committed to reducing its total greenhouse gas emissions by 70% compared to 1990, by 2030. In addition, the government has endorsed the views on Europe's long-term strategic vision of a "clean planet for all", with which Estonia supports, in principle, the goal of climate neutrality across the European Union by 2050.

To meet the objectives, GHG emissions need to be reduced in the energy, building, transport, and industrial sectors. To achieve these reductions, Estonia has a vision of growing electricity generation from renewable sources and at the same time electrifying big parts of energy consumption that currently use fossil fuels. Service and industry sector electricity demand is led by the organic growth of the economy, the digitalisation of the society, and increased implementation of automation and robotisation. However, decarbonisation will lead the electrification by switching from solid fuels, liquid fuels, and natural gas to electricity. In the heating sector biomass and fossil fuels load could be replaced by heat pumps and electric boilers, combined with heat storage. In addition, new and renovated buildings must follow and meet the energy performance requirements. Buildings that are required to have A-class energy performance, must use local solar energy production to achieve the A-class. Buildings have significant solar energy potential, to enable the switch to renewable energy and cover the increase in electricity demand. Moreover, decarbonisation of transportation sector will be biggest challenge, as demand for passenger and cargo transport is expected to continue increasing rapidly.

To conclude, distribution grid energy consumption can be divided into four sectors: household, services, industry, and transportation. Figure 1.1 illustrates different factors that are considered in the model. The scenarios differ in the speed and extent of electricity demand growth and indicate the expected yearly electricity demand and the peak power for consumers without local load management (building load management), consumers with local load management and finally the transmission network demand. The electricity demand values are determined for an average and extreme climatic year.

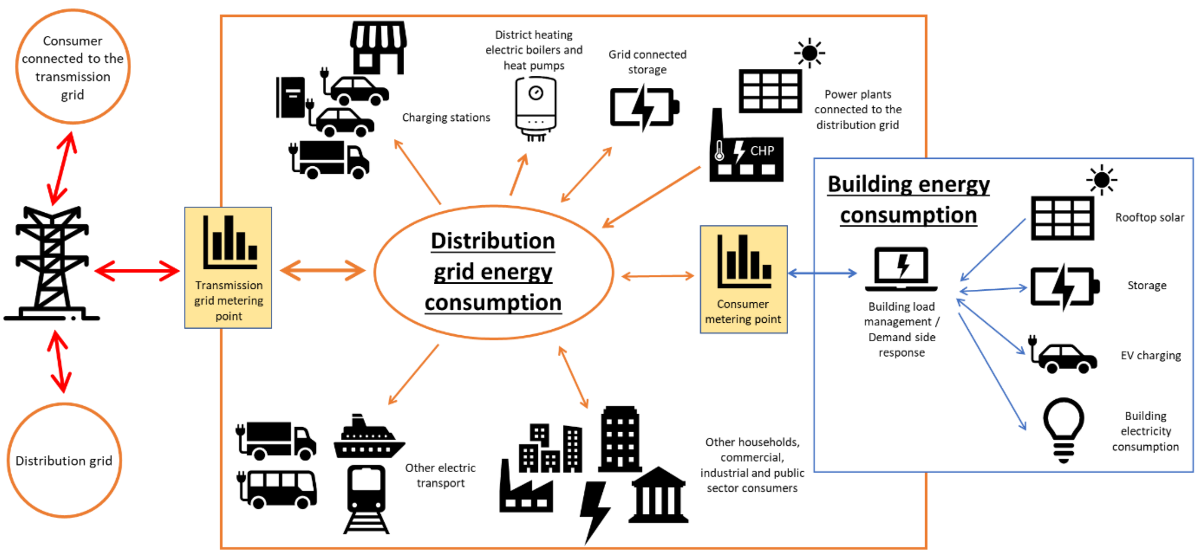


Figure 1.1. Factors considered in the study

1.1. Base consumption model

Multiple linear regression analysis was carried out to determine the base demand model and base consumption increase due to organic growth of the economy, the digitalisation of society, increased implementation of automation and robotisation. 11 years (2010-2021) of historic annual hourly consumption of electricity was used as dependent variable [4]. The input data are the consumption data of Elering's 110 kV substations and therefore include electricity production by micro-producers, which effectively reduces the demand by a small amount. In addition, losses are calculated separately and are not included in the base consumption model. Total of 37 independent variables were used. Fourier transform was used to analyse seasonality in a regression. 20 Fourier-curves to model the daily winter and summer demand curves. In addition, 14 dummy variables were added to indicate the absence or presence of categorical effect. To determine the load temperature dependency and climatic factor, ambient air temperature was converted to heating and cooling degree hours. Up to three days of heating degree hours were included to compensate for temperature dependency inertia. The model describes 91% of the variance of the dependent variable.

Dependent variable used in the model:

c – historic hourly electricity consumption in megawatts.

Calculated variables:

w_{ci} – five fourier cosine series for winter seasonality, 0 – 1 range.
w_{si} – five fourier sine series for winter seasonality, 0 – 1 range.
s_{ci} – five fourier cosine series for summer seasonality, 0 – 1 range.
s_{si} – five fourier sine series for summer seasonality, 0 – 1 range.
hdh – heating degree hours in kelvins, calculated with bivalent temperature for up to 48 hours.
cdh – cooling degree hours in kelvins, calculated with bivalent temperature.

Integer variables

wkd – weekend, equals 1 if Saturday or Sunday, otherwise equals 0.
ho – holiday, equals 1 if national holiday date.
loho – long holiday, equals 1 if national holiday is followed up with the weekend.

Dummy variables:

2010-2021 – dummy variables, 2021 as base and equals 0 else equals 1 if date includes corresponding year, otherwise equals 0.

Figure 1.2 represents the yearly dummy variable regression coefficient values as dependent variable. Regression coefficients describe the hourly consumption difference of hourly electricity consumption compared to base the year 2021 consumption. 2020 was excluded as outlier due to COVID-19 pandemic. A separate simple linear regression between year and yearly dummy variable regression coefficient value was used to compile the function for 2025-2050 period. Figure 1.3 represents the output of linear regression function for 2025 to 2050. The model describes 85% of the variance of the dependent variable.

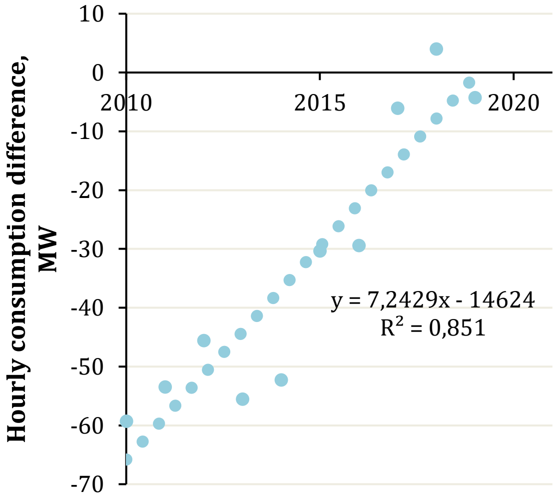


Figure 1.2. Dummy variable result regression

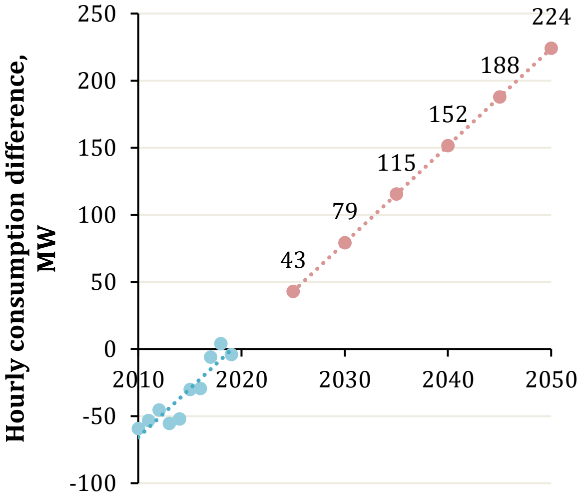


Figure 1.3. Base model regression extrapolation

1.1.1. Climatic years for the model

The model calculates electricity peak demand values for an average climatic year (ACY) and two different types of extreme climatic years (ECY and ECY2). Actual historic measurements of last 17 years are used instead of theoretical values. To find the average climatic year, ambient temperatures are transformed into heating degree hours and the year closest to the average is used as the *average climatic year* for the model. The year with the highest heating degree hours within the historic data is the coldest and therefore the *extreme climatic year*. As the model considers two types of extreme climatic years, in order to find an extreme climatic year with a warm summer (ECY2) or a cold summer (ECY), cooling degree hours are used. Thus, the year with highest cooling degree hours during summer has the warmest summer and the year with lowest cooling degree hours the coldest summer. Table 1.1 represents the 17 years of historical measurements from Estonian Weather Service [5].

Table 1.1. Climatic year dataset

Year	Temperature (T), °C	T-AVG	HDH	HDH-AVG	CDH	CDH-AVG
2004	6.0	-0.6	91375	3773	272	-371
2005	6.1	-0.5	91403	3800	378	-266
2006	6.6	0.0	88284	682	848	204
2007	6.9	0.3	85281	-2322	546	-97
2008	7.2	0.6	79978	-7625	56	-587
2009	6.0	-0.6	91197	3594	133	-510
2010	5.0	**-1.6**	104422	**16820**	1669	**1025**
2011	6.9	0.3	85920	-1683	943	300
2012	5.4	-1.2	96682	9079	253	-390
2013	6.6	**0.0**	88235	**632**	514	-129
2014	6.8	0.2	86822	-781	1300	656
2015	7.4	0.8	78769	-8834	268	-376
2016	6.5	-0.1	88539	937	281	-362
2017	6.3	-0.3	87728	125	56	**-587**
2018	7.0	0.4	86779	-824	1486	842
2019	7.3	0.7	81321	-6282	585	**-58**
2020	8.2	1.6	73291	-14311	435	-209
2021	6.5	-0.1	90823	3220	1557	914
Average (AVG)	**6,6**		**87603**		**643**	

Based on calculations, 2010 had a cold winter and a hot summer. 2017 had the coldest summer. 2013 average temperature is closest to the 17-year average temperature. Based on heating degree hours 2017 heating period would be an alternative average climatic year. 2013 was chosen with the contractor for the model. 2019 summer coolding degree hours are closest to the 17-year average. In conclusion, climatic years are as follows.

1. **Average climatic year (ACY):** 2013 heating period and 2019 summer. (Figure 1.4)
2. **Extreme climatic year (ECY):** 2010 heating period and 2017 summer. (Figure 1.5)
3. **Extreme climatic year (ECY2):** 2010. (Figure 1.6).

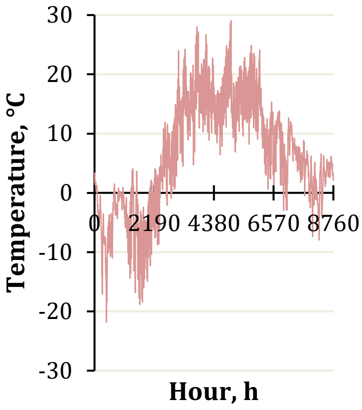


Figure 1.4. ACY

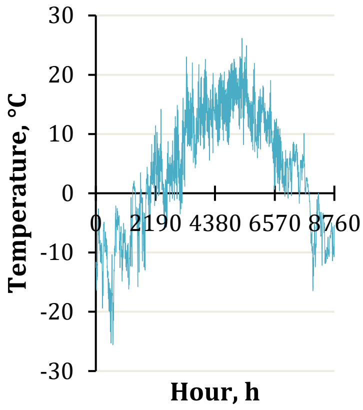


Figure 1.5. ECY

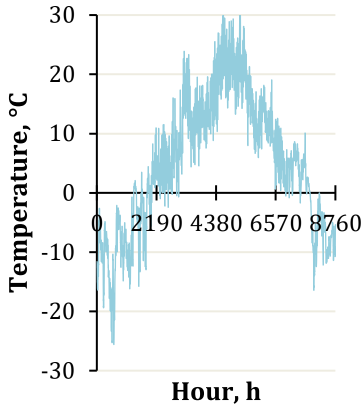


Figure 1.6. ECY 2

1.1.2. Base model sector consumption

Simple regression was conducted on 11 years of historic sector specific annual consumption as seen on Figure 1.7 [4, 6, 7]. Transport sector's consumption had steadily decreased during 2010 to 2013 and regression from 2010 to 2020 would result a negative trend, extrapolating to 0. Therefore, transport sector consumption regression includes data since 2014 as transport electrification is an emerging sector in electricity consumption. Today, a small share of the transport sector is already electrified and therefore it is captured by the regression model. However, as this share is small, it does not have a major effect on forecasting and shall represent just the already existing part of electric transport in the result. Figure 1.8 represents the output of linear regression function for 2025 to 2050. Regression estimates that services' consumption will increase the most as it has been increasing steadily since 2010. Base model sector consumption percentages that are used in the model are seen on Figure 1.9.

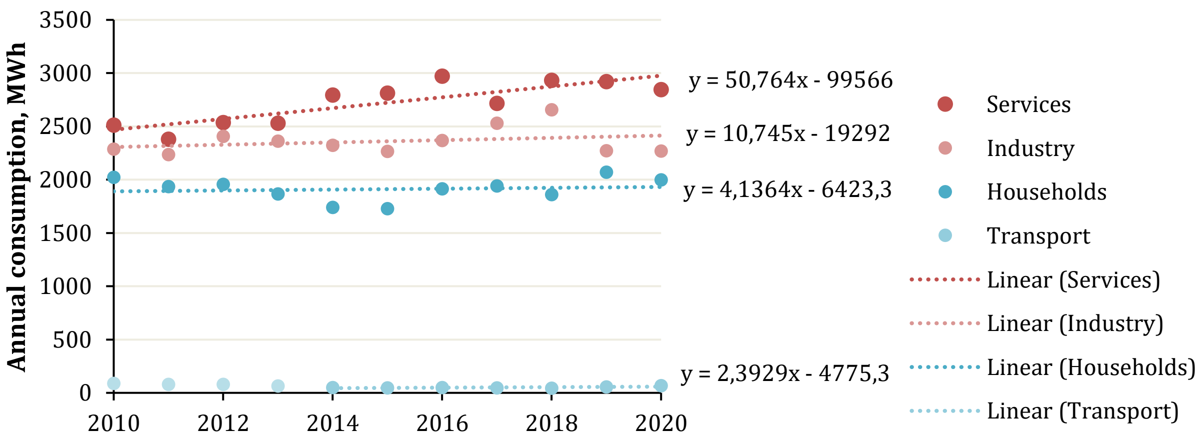


Figure 1.7. Sectors' consumption regression

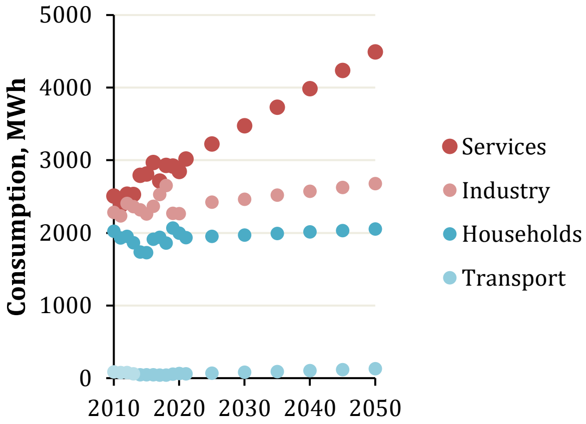


Figure 1.8. Sectors' regression extrapolation

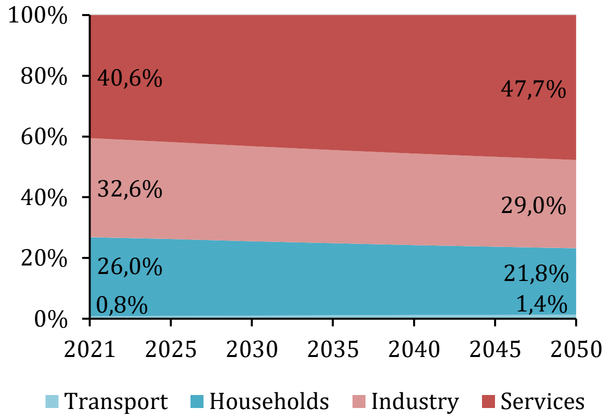


Figure 1.9. Sectors' consumption percentage

1.2. Sector-specific models

Three electrification scenarios for all the sectors were compiled by the authors. **Three scenarios of electrification are as follows: low, base, and high.** Base scenario follows previously compiled studies, strategies, and roadmaps. Low and high scenario is a deviation of the base scenario. Detailed percentages of all the inputs are in each of the sectors sub-paragraphs.

2. Electricity demand scenarios

2.1. District heating

District heating is a proven technology to enable heating and domestic hot water in populous areas. It also enables the integration of renewable energy sources into the energy system. Supplying heat produced with heat pumps to them is a solution with great potential in rural areas, as available land for such purposes is plentiful. In addition, heat pumps can help increase air quality, as they can replace heat produced by combustion of biomass or fossil fuels.

Estonia's 2030 National Energy and Climate Plan (NECP) collected district heating (DH) network's consumption data in 2013. Estonian district heating networks annual heat consumption is about 4.6 TWh. Nearly 3.6 TWh is produced by large district heating networks with combined heat and power (CHP) plants (Figure 2.1). Nearly 78% of district heating heat production is produced by combined heat and power plants. NECP estimated in one scenario that district heating consumption will be 3,5 TWh by 2050 (Figure 2.2). Therefore, it is expected that rural district heating networks will be shut down or electrified due to demographic movement to bigger cities which causes higher renovation costs and heat production prices within rural district heating networks [8]. To compile the district heating model, only district heating networks without CHP will be included (displayed red on Figure 2.1).

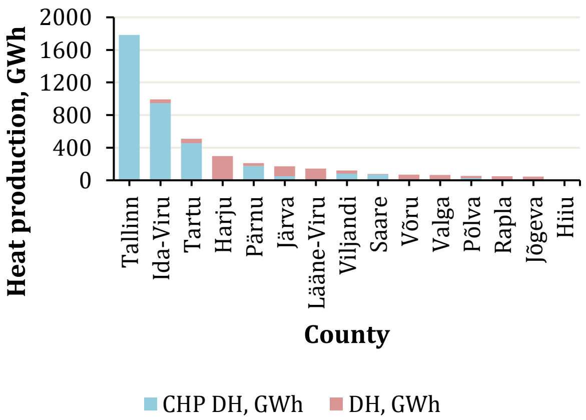


Figure 2.1. District heating production (2013)

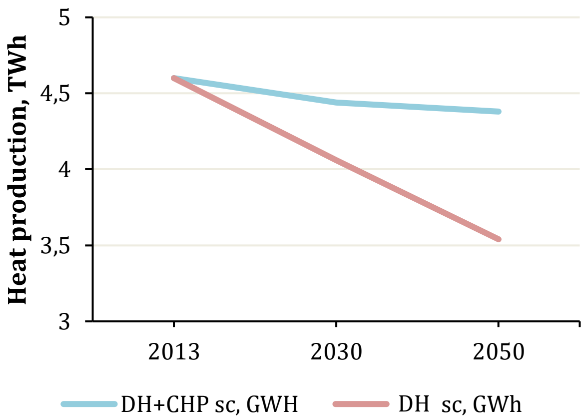


Figure 2.2. NECP scenarios

2.1.1. District heating methodology

To estimate the electrification of rural areas with district heating networks, the model is based on study that is focused on heat pump use in rural district heating networks in Estonia. The study focused and gathered information about the district heating networks with annual consumption of less than 16 GWh (Table 2.1). 16 GWh was chosen as the threshold as all networks with consumptions under this level can be considered as rural. Average population in these areas is from 165 to 5000 residents. Only rural areas were considered because heat pump integration is especially important in these areas. [8] Total of 498.5 GWh of heat is consumed annually by the rural district heating networks. For all district heating networks, annual heat consumption profile is calculated using bivalent temperatures. The coefficient of performance of the heat pump is used to convert district heating heat consumption to electricity (Figure 2.3) [9].

The model takes as input the estimation of percentage of networks being converted to local heating system and the use of heat pumps. In addition, the model requires electrification conversion rate till 2050. The authors agree that the electrification of district heating networks will begin slowly in the next ten years because Estonian Environmental Investment Centre is still funding biomass boiler installations for district heating companies. It is expected that the funding will stop after 2025 and the most of previously built biomass boilers will reach the end of their efficient lifespan by 2040 [10].

However, both base and high electrification scenario models expect all under 16 GWh district heating networks to be converted to other methods by 2050 due to the demographic movement from rural areas to bigger cities [11] where over 50 GWh district heating networks are operating which were not included in the electricity demand model. 16 GWh is an expert assumption over which it is unlikely for networks to fully switch to heat pumps. The authors have noticed a decline in consumption in low consumption district heating networks due to demographic movement (which can also result in shift to local heating) when compiling heat management development plans for district heating networks. Moreover, as electricity production is shifting towards renewables and the number of countries announcing pledges to achieve net zero emissions by 2050, the authors expect that rural district heating networks will be converted to other methods [12]. Though, low electrification scenario expects only half of the given district heating networks to be converted. In addition, low and base scenario model expects half of converted district heating networks to use heat pumps. After all, district heating consumers have the option to use local biomass boiler as well (pellet for example). Cumulative electrification of district heating networks considering all the parameters discussed before is seen on Figure 2.4.

Table 2.1. District heating networks' data

District Heating (DH) Group	1	2	3	4	5	6	7
Number of DH networks	23	58	24	8	8	9	5
Annual normalised consumption, MWh	15 663	111 012	94 944	49 880	62 496	93 537	70 960

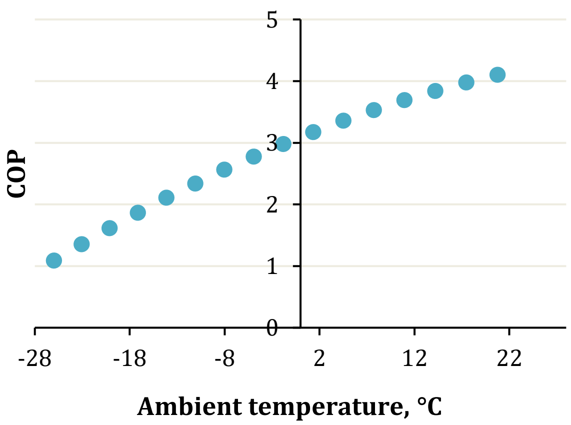


Figure 2.3. Heat pump efficiency (COP)

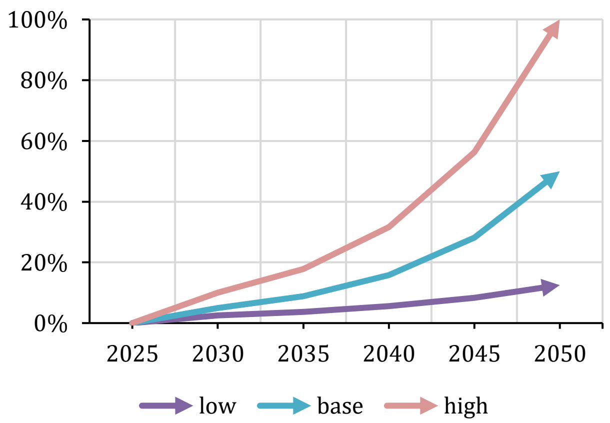


Figure 2.4. Electrification rate of the demand scenarios

2.1.2. District heating summary

Figure 2.5 represents the summary of district heating scenarios. Total of 498,5 GWh of heat is consumed annually by given district heating networks. Three scenarios expect such district heating networks to be electrified by 100%, 50% and 13%. To estimate potential additional electricity consumption, it is important to consider heat pump coefficient of performance.

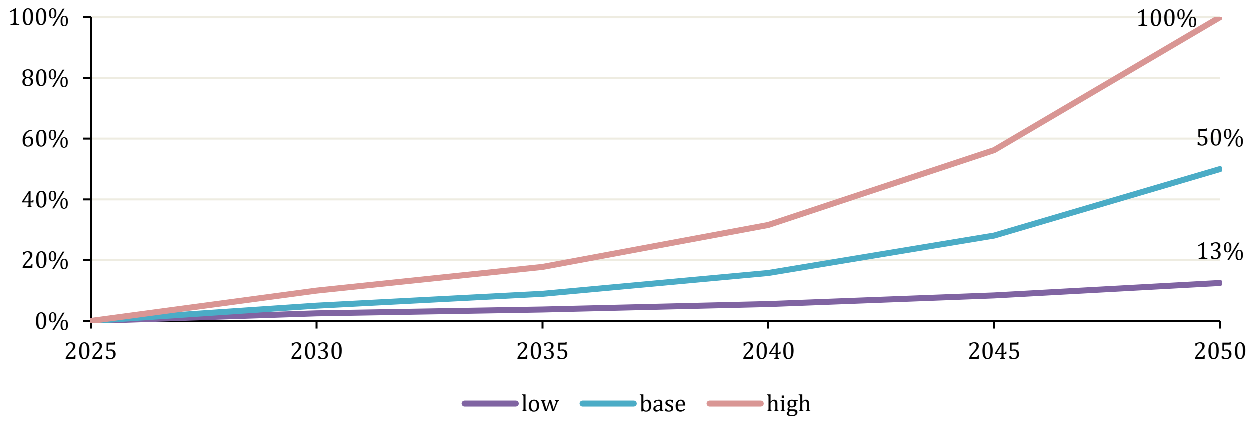


Figure 2.5. District heating scenarios

Figure 2.6 - Figure 2.7 describe the resulting electricity consumption from the use of heat pumps in small (<16 GWh heat consumption) district heating networks during average and extreme climatic years (in the base scenario). Although the effect of district heating network electrification on overall demand is smaller compared to, for example, the effect of the electrification of the transport sector, the peak power of smaller networks is expected to be around 100 MW.

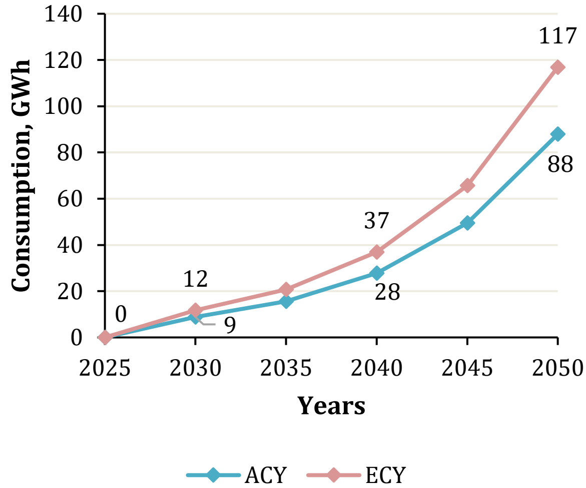


Figure 2.6. DH electrification electricity consumption

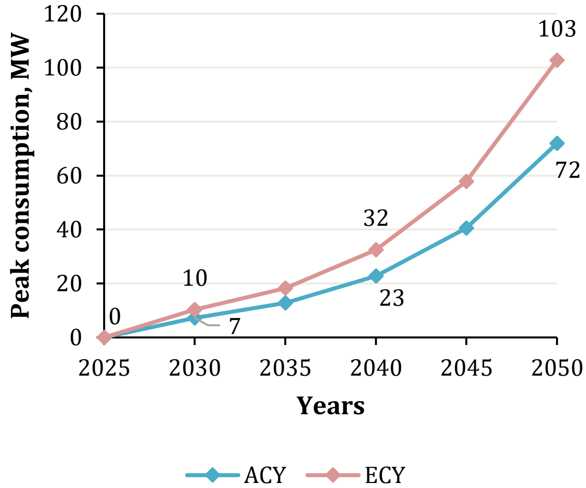


Figure 2.7. DH electrification electricity peak consumption

2.2. Natural gas electrification

2.2.1. Natural gas methodology

As Estonia is committed to reducing its total greenhouse gas emissions by 70% compared to 1990, by 2030, it is necessary to reduce fossil fuel consumption, including natural gas, in all sectors where this is possible. Moreover, in the 'Fit for 55' package, the European Commission has proposed the expansion of the Emissions Trading System (ETS) to building sectors, starting from 2026. Natural gas is currently used in boiler-houses and combined heat and power stations (CHP) mainly in peak heat demand situations, in industries for the heating of buildings but also in industrial processes where high temperatures are required, in households and in the service sector for heating of buildings, and in transport as the government has incentivised the use of natural gas vehicles to facilitate a transition to biogas use. A large part of natural gas consumption can be replaced by electrification in all these sectors, especially the consumption for heating buildings. [14]

To estimate the electrification of natural gas consumption, the model is based on study that created natural gas consumption scenarios till 2050. The study estimated electricity consumption from 2025 to 2050 [14]. The consumption of natural gas for heating purposes is estimated by the model. It uses the estimated energy consumption and generates an annual hourly demand profile. To modify the profile, it is required to estimate the bivalent temperature and heat consumption that is independent of degree heating hours. Indoor heating covers losses from the temperature of the outside air to bivalent temperature. Heat losses from the bivalent temperature to a building's indoor temperature are covered by internal heat gain. Therefore, bivalent temperature is lower than actual indoor temperature. Generally, domestic hot water and industrial processes have no temperature dependency and are independent of ambient temperature and therefore degree heating hours.

Figure 2.8 represents the base scenario for natural gas electrification. The largest potential for electrification is in service and household sector where most of the current natural gas demand could be replaced by electricity. Base scenario electricity consumption that will replace natural gas consumption is seen on Figure 2.9. While, the industry sector has the smallest percentage of electrification, it has the highest electricity consumption potential. In addition, the industry sector has the widest selection of alternatives for industrial processes. Instead of natural gas, the industry can implement the use of biogas, biomethane, biomass, hydrogen, and electricity. Whereas it is likely that household sector will only use biomass and electricity. On the figures CHP represents both boiler-houses and combined heat and power plants.

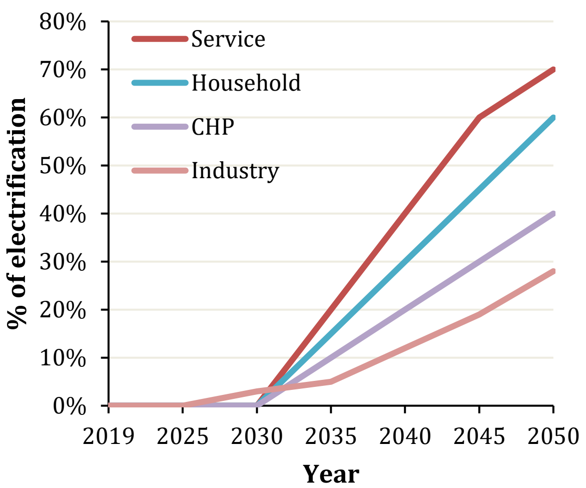


Figure 2.8. Base scenario for natural gas electrification

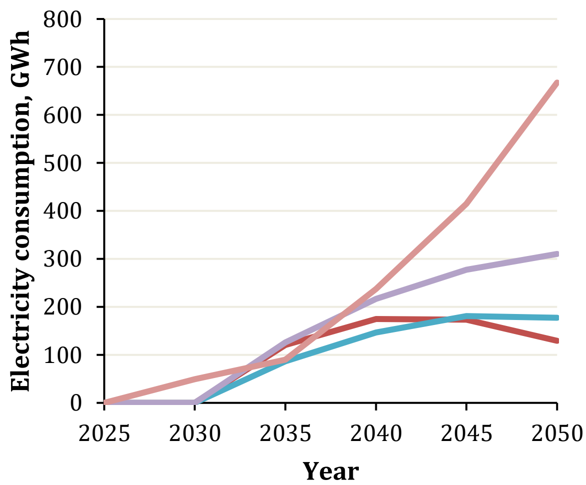


Figure 2.9. Base scenario electricity consumption

2.2.2. Natural gas summary

Figure 2.10 -Figure 2.13 represent the natural gas electrification scenarios. Scenarios are based on the "Estonian Gas Market Study – Consumption Forecast Until 2050" study. Low electrification scenario expects natural gas to be replaced with other alternative fuels, whereas high electrification prioritizes electricity. Percentage wise household and services have the highest electrification potential, but large district heating networks and industries combined consume twice as much as the households and service sector. Moreover, district heating and industry sector have more alternatives to natural gas. Therefore, their scenarios are compiled that all alternative energy sources are increased proportionally.

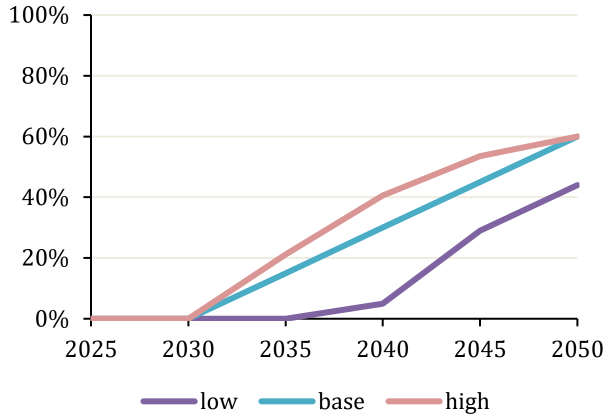


Figure 2.10. Household natural gas scenarios

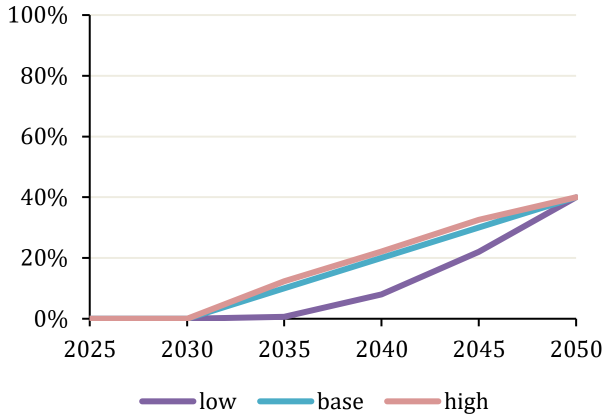


Figure 2.11. CHP DH natural gas scenarios

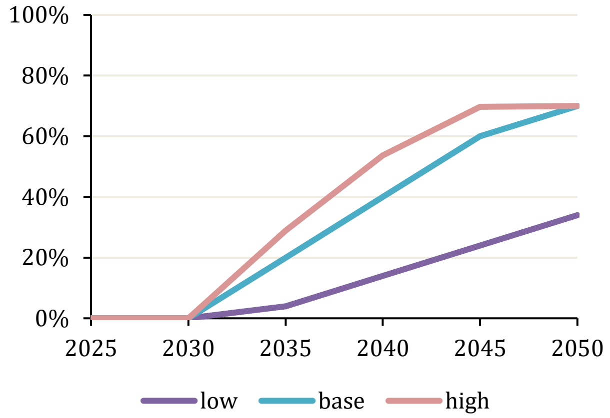


Figure 2.12. Services natural gas scenarios

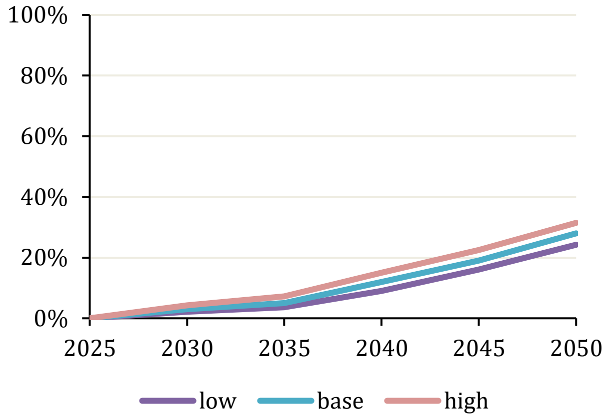


Figure 2.13. Industries natural gas scenarios

Overall electrification of the natural gas is seen on Figure 2.14. Difference between high and base is low because of consumption differences mentioned previously. However, small difference in percentage results in over 200 GWh of electricity consumption difference.

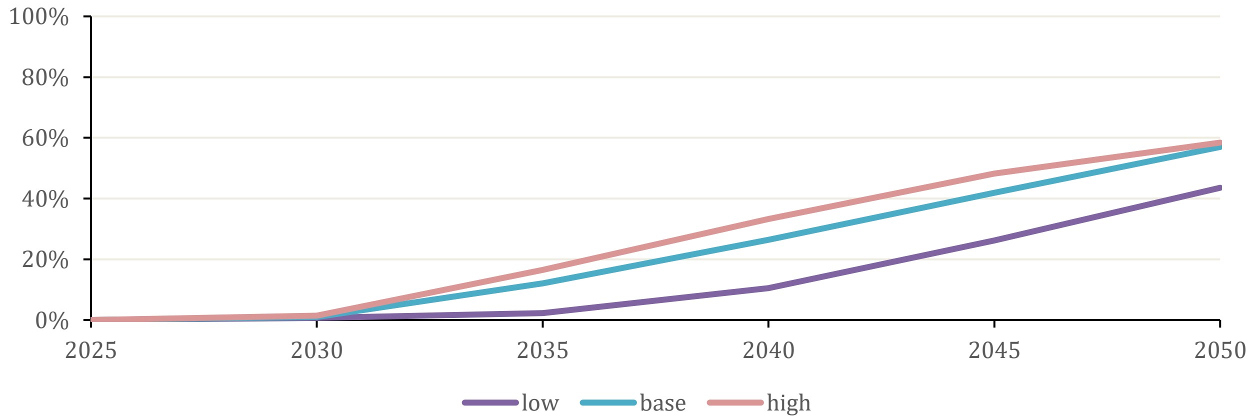


Figure 2.14. Natural gas electrification

Figure 2.15 and Figure 2.16 describe electricity consumption and peak power demands in the base scenario (average and extreme climatic years) arising from the electrification of natural gas consumption. Electrification in this field has a higher effect on overall demand than the electrification of rural district heating networks. While yearly demand is similar for different climatic years, peak power varies significantly between them.

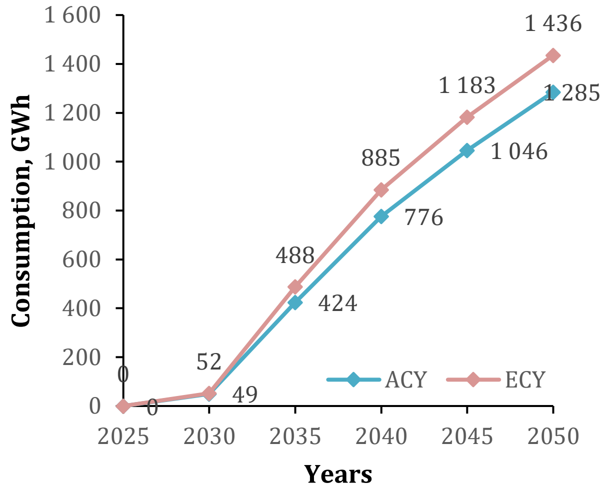


Figure 2.15. Natural gas electrification consumption (base scenario)

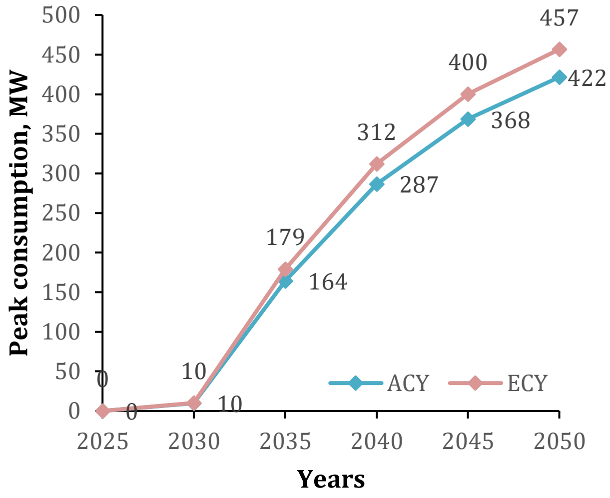


Figure 2.16. Natural gas electrification peak consumption (base scenario)

2.3. Buildings

2.3.1. Buildings methodology

To estimate the building renovation effect on electricity consumption, the model is based on the long-term strategy for building renovation. The main goal of the strategy is to fully reconstruct all buildings, that were built before the year 2000, by the year 2050. The strategy sets out to reconstruct all buildings to energy class C by the year 2050, this means that in the next decades, 100 000 single-family dwellings, 14 000 apartment buildings and 27 000 non-residential buildings need to be reconstructed. This has also been agreed upon in the EU Green Deal which results in EU funds being directed to the renovation of buildings as well. Cooling is not considered in this part of the model, however the increasing level of cooling capacity is in principle covered by the base consumption model.

Monthly energy consumption is calculated based on heating degree hours (Figure 2.17) [15]. On Figure 2.17 for ACY a kink can be observed in March due to actual weather data of the chosen average climatic year (Paragraph 1.1.1). To estimate the hourly load, fixed percentages of nominal load is distributed throughout the day and later multiplied by the annual consumption. The category “Other” includes service and industry buildings. The authors used their energy audit experience to compile different profiles for sectors (Figure 2.18). To modify the profile, it is required to estimate the bivalent temperature and heat consumption that is independent of degree heating hours for ventilation and domestic hot water.

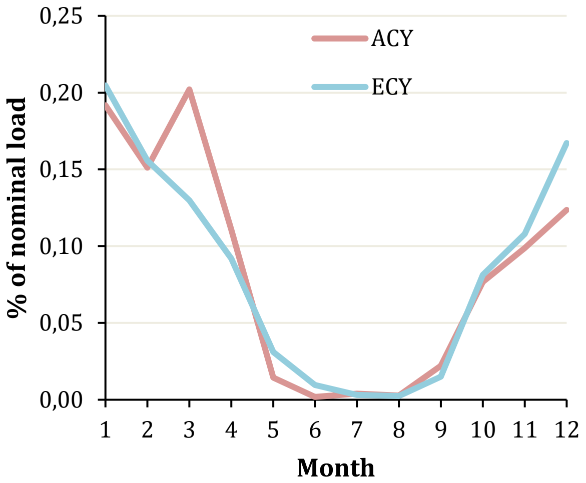


Figure 2.17. Monthly load profile of buildings

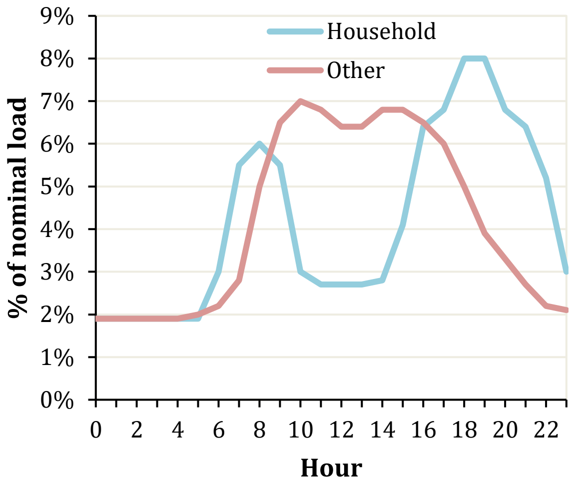


Figure 2.18. Hourly load profile of buildings

Figure 2.19 represents the percentage of surface area to be renovated in base scenario. Cumulative renovation is seen on Figure 2.20.

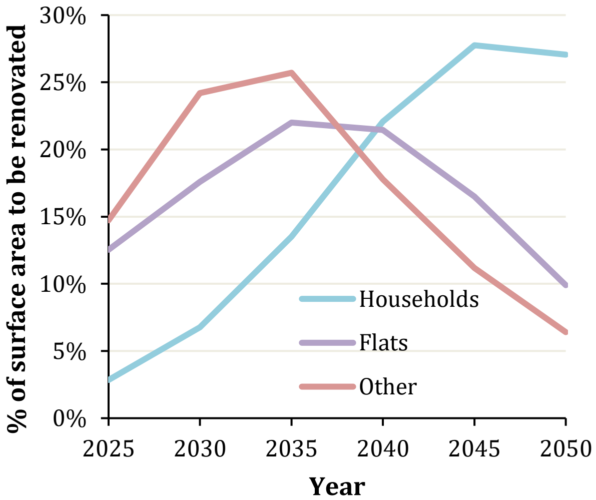


Figure 2.19. Base renovation strategy

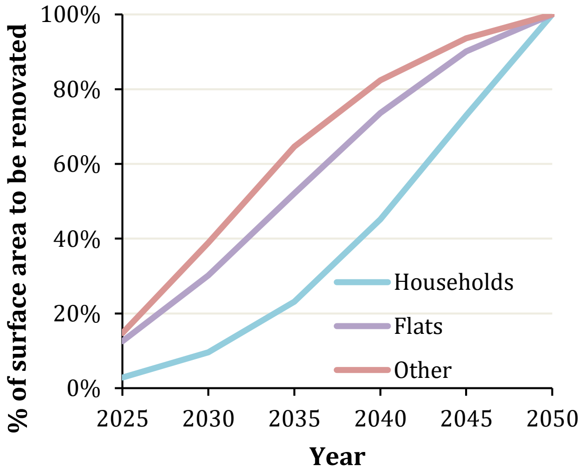


Figure 2.20. Cumulative renovations

Figure 2.21 represents the change of electricity consumption after renovations. Cumulative consumption change is seen on Figure 2.22. The consumption of electricity may increase in buildings that did not previously have a mechanical ventilation system due to the technical systems that ensure the indoor climate by consuming electricity, even though overall energy consumption shall most likely fall.

To estimate the new households and flats energy consumption, historical data of houses built, and their average surface area since 2000 is considered to calculate new buildings' electricity consumption by 2050. The model does not include the possibility of increasing surface area of the buildings. Increasing surface area of living spaces will make it harder for buildings to achieve the necessary energy efficiency values. Energy consumption assumptions are from long-term strategy [15]. Other buildings include private sector and local government buildings. Historical data is also used to estimate number of new other buildings and their surface area. Buildings below 20 m^2 surface area are not considered in the model [16]. The demolition of buildings is also considered. To estimate the other buildings' new electricity consumption, 65 $kWh/(m^2a)$ is assumed to be average of all other buildings [17].

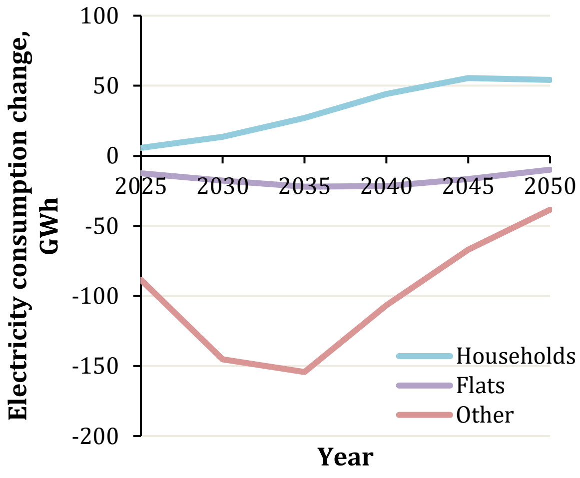


Figure 2.21. Base scenario consumption change

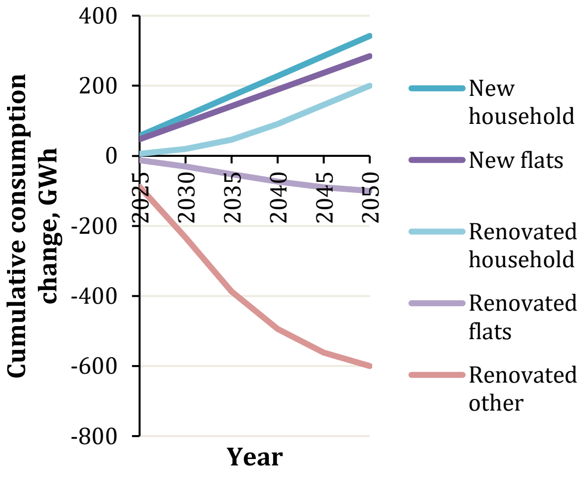


Figure 2.22. Cumulative consumption change

2.3.2. Buildings summary

Figure 2.23–Figure 2.26 represent buildings renovation scenarios. The high scenario foresees that 30% of buildings shall be renovated by 2030 and the renovation rate is held about the same level until 2040. Base scenario follows the long-term strategy and renovation rate increases every year until all the buildings are renovated. Low scenario expects that renovation will be slower than the base scenario and renovation rate will be highest during 2050, right before the net zero by 2050. Overall renovation of buildings is seen on Figure 2.26.

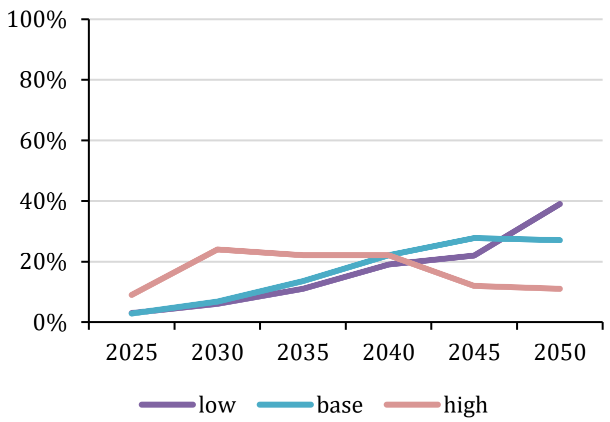


Figure 2.23. Household renovation scenarios

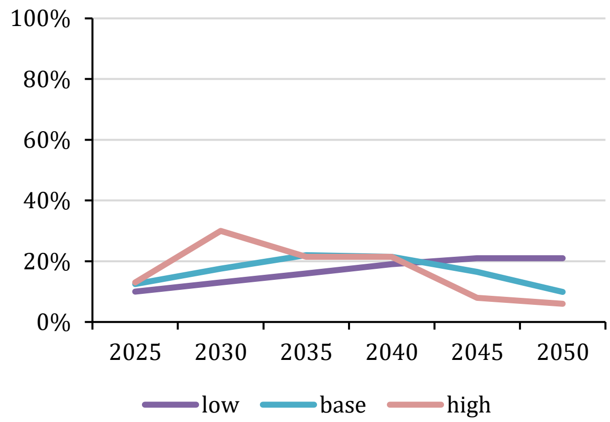


Figure 2.24. Flats renovation scenarios

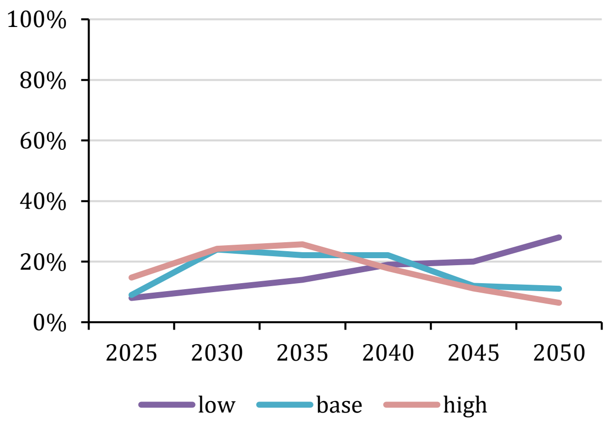


Figure 2.25. Other buildings renovation scenarios

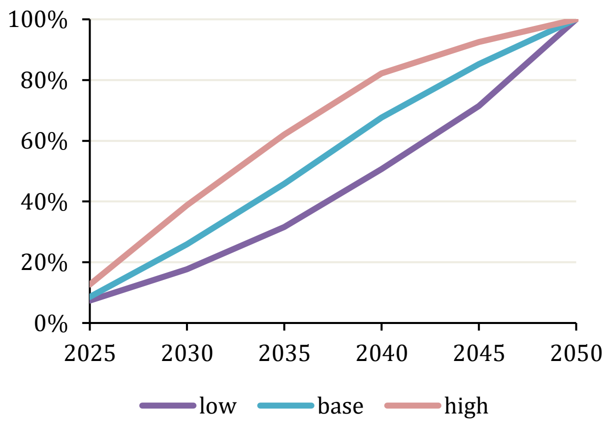


Figure 2.26. Overall renovation

Figure 2.27 – Figure 2.28 describe the effect of building renovations on yearly electricity demand and peak consumption in the base scenario on an average climatic year. Extreme climatic year has not been shown on the graph, as the demand figures are very similar. Overall electricity consumption in the sector shall increase as new technical systems that consume electricity, are introduced in the buildings, but more importantly, heating consumption of buildings shall be more electrified in the future.

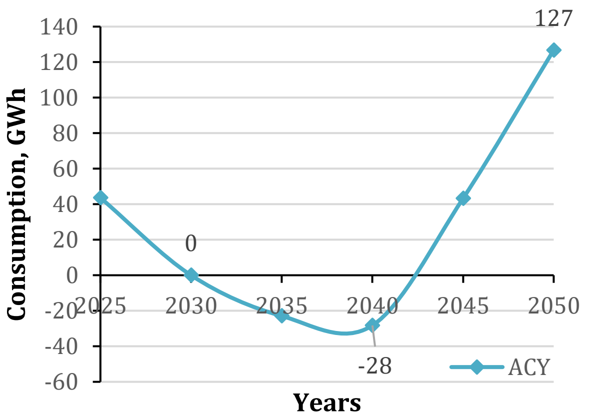


Figure 2.27. Buildings electricity consumption (base scenario)

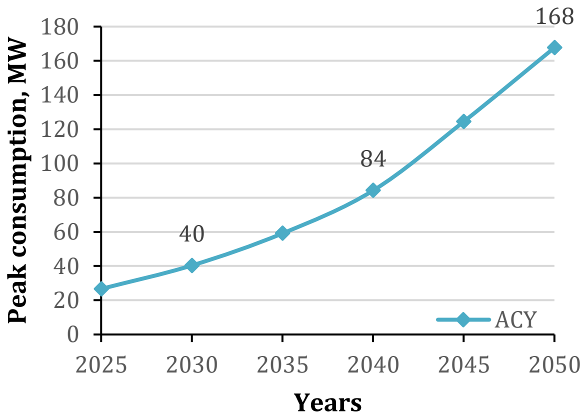


Figure 2.28. Building peak consumption (base scenario)

2.4. Solar power

2.4.1. Solar power methodology

The model for solar power production is based on the long-term strategy for building renovation, the requirement for all new buildings with over 220 m² of heated floor area to have a renewable energy source (usually solar power) if economically and practically justified along with assumptions about old buildings installing solar power solutions [18] [19]. The data is taken from the national building registry and extended statistically to convert the net area of buildings into roof area from where the produced energy can be calculated taking the roof area covered by solar panels as a variable. The prediction for ground-mounted solar power farms is based on the IRENA prediction for Europe which is extended to Estonia [20]. Current large PV installations in distribution grids and additional generation predicted to be connected to the distribution grid are considered based on recent renewable energy auctions.

The model makes several assumptions about the trends of solar power installations. Only 20+ m² grid connected buildings were considered viable for rooftop solar energy. The aging of the panels is taken into account in system losses, which is an average value to represent the linear losses in inverters, cables, panel mismatch and the shading of the panels due to dirt or snow. The effects of the outside temperature is technology-, site- and installation-dependent along with panel aging and thus is not considered precisely in the model but rather through average values. The results of the model will be conservative as the energy produced will be slightly lower in the summer, given the rather mild summers of Estonia, and due to the cold temperature slightly higher in winter than the model predicts. The solar radiation data is based on the 2005-2016 Estonian average which means that there will be spikes of solar radiation that give higher production peaks than is predicted by the averaged model. The efficiency of research cells have been steadily increasing from less than 10% in the 80s to almost 45% in 2022, the benefits of which have trickled down to consumer panels [21]. The efficiency of non-concentrating commercial cells (cells that do not use mirrors etc, that would concentrate solar radiation to a smaller area thus increasing the efficiency) is taken to reach 36% by the year 2050 based on a linear trend. The panels installed in the later years will be more efficient in converting incident solar radiation to electrical energy leading to an increase in energy produced per m² of installed panels. The model also assumes linear yearly increase in the percentage of the roof area that is covered by solar panels. Wallmounted and building-integrated solar panel technology is factored in with the losses due to suboptimal placement as these technologies tend to produce less energy due to decreased air flow and technological factors. The baseline roof coverage and annual increase in roof coverage are adjusted to produce the low, base and high scenarios (Figure 2.29 – Figure 2.30).

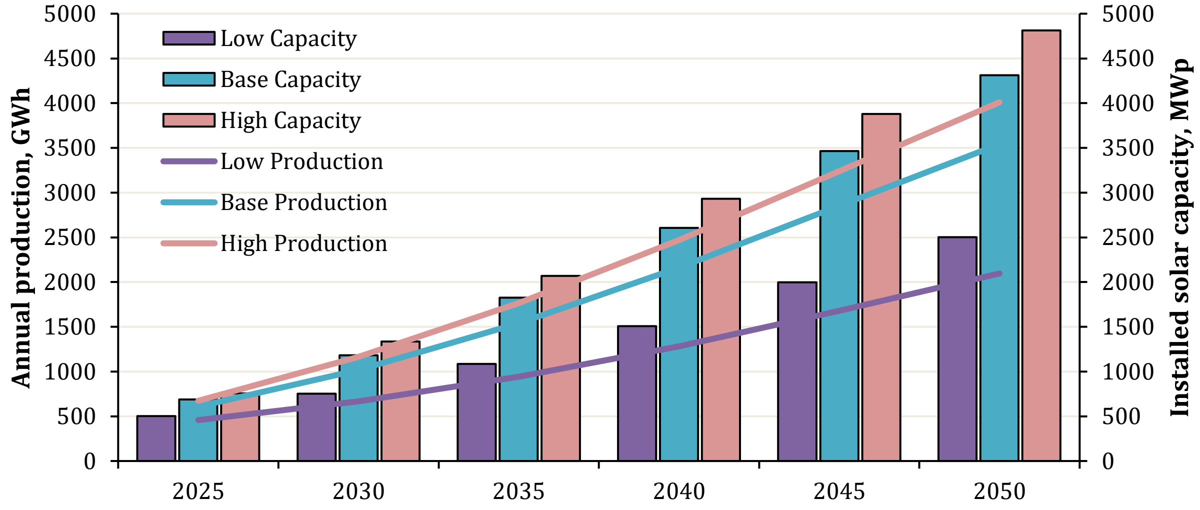


Figure 2.29. Solar power scenarios

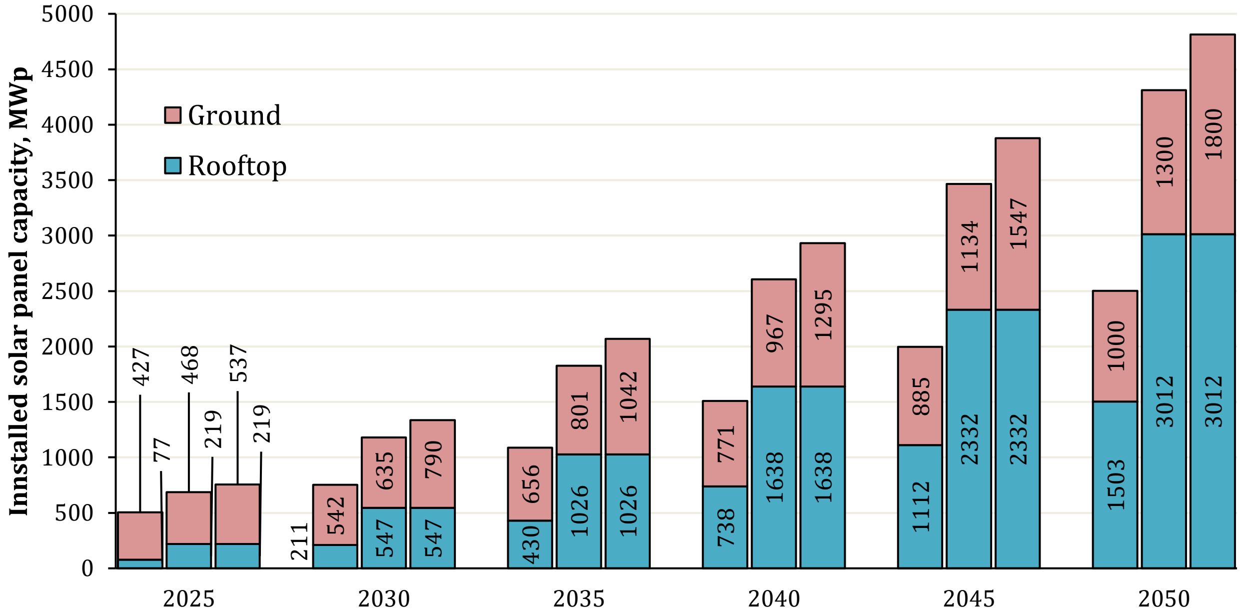


Figure 2.30. Distribution of rooftop and ground solar installations. Low, base and high scenarios from left to right.

The model calculates the installed solar power capacity using roof coverage and average solar irradiation or insolation. The model calculates the installed photovoltaic (PV) capacity from the percentage of the area of a flat roof that is purely covered by optimally placed solar panels not including the necessary spacing between the panels and safety clearance. Some buildings and areas of the roof are also unsuitable for the installation of solar panels due to carrying capacity, shadows or obstructions of the roof like windows or chimneys. In general, this means that the covered roof area should generally not exceed 50%. This number can be higher or lower depending on the type of building – apartment buildings tend to be higher and have less obstructions from the shadows of adjacent buildings or trees. Detached houses are more easily overcast as a vast majority of them have only one floor. Service and industrial buildings are mostly single-storey as well but tend to have larger areas which decreases cast shadows on the roof by adjacent buildings and forest. The results of the analysis are compatible with the pan-European geospatial PV potential assessment [22]. The model generally assumes an increase in the solar energy installations which can and should be adjusted along with the initial roof coverage values based on real-world data to get a more accurate forecast. The base and high scenarios differ by ground solar park capacity. The difference with the low scenario is illustrated in Table 2.2. It was assumed that PV installations would get more popular after each 5-year interval with the initial values and their linear increments set for every type of building. The trend value shows how much of a buildings roof area on average would be covered by a new PV panel installation by 2050 or how likely it is for a type of building to cover its roof fully with PV panels during a 5-year period by 2050. **The results are a best estimate based on the building renovation and decommissioning strategy and government statistics with the base/high scenario being more successful. The estimation is rather conservative as can be seen from the total covered roof area.**

Table 2.2. Comparison of the 2050 results for roof mounted PV

Scenario:		**Low**			**Base/High**		
Building type:		Detach.	Apt.	Other	Detach.	Apt.	Other
New:	Total covered roof area, %	3%	20%	9%	7%	40%	20%
	Installed capacity, MWp	51.5	74.0	316.5	103.1	148.3	633.5
	Trend by 2050	7%	27%	20%	10%	47%	30%
Renovated:	Total covered roof area, %	3%	9%	6%	6%	19%	11%
	Installed capacity, MWp	158.5	252.0	465.5	317.1	503.8	937.0
	Trend by 2050	6%	19%	14%	10%	32%	25%
Old:	Total covered roof area, %	0%	2%	2%	1%	4%	3%
	Installed capacity, MWp	12.4	27.4	145.4	24.9	54.6	290.1
	Trend by 2050	0%	0%	0%	0%	1%	1%

2.4.2. Solar power summary

Figure 2.31 –Figure 2.32 represent the rooftop and ground solar photovoltaic (PV) scenarios. Ground solar PV scenarios are seen on Figure 2.32 separately. Ground solar PV installed capacity is the main difference between base and high scenario. The REPowerEU plan is to rapidly deploy massive amounts of renewable energy with solar PV panels [23]. Ground solar PV scenarios are based on Estonia's 2030 National Energy and Climate Plan. The larger implementation of ground solar parks is based on the IRENA solar data that is taken for Europe and then extended to Estonia [20].

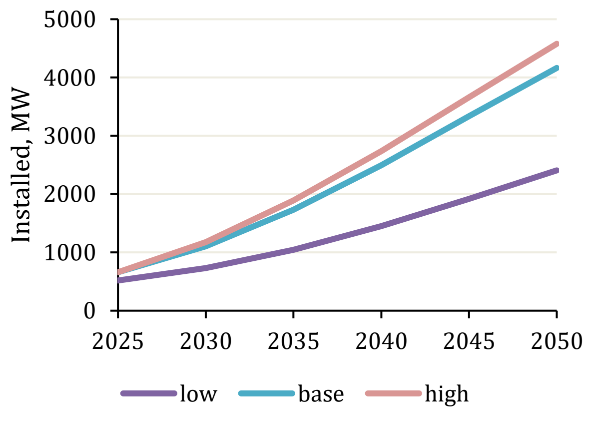


Figure 2.31. Rooftop and ground PV scenarios

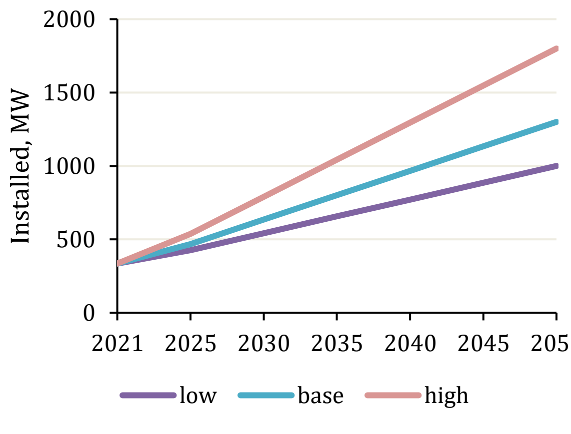


Figure 2.32. Ground PV scenarios

2.5. Transport electrification

In the transport sector Estonia has set a goal to reduce greenhouse gas emissions by 60% by the year 2050 compared to 1990. The main ways Estonia plans to do this, is at first introducing more fuel-efficient petrol and diesel vehicles and subsequently replacing them with hybrid and electric vehicles. The uptake of electric cars and vans has recently been significantly increasing in Europe. Electric car registrations for the year 2020 were close to 1,325,000 units, up from 550,000 units in 2019. This represents an increase from 3.5% to 11% of total new car registrations in just 1 year. The uptake of electric vans also increased, from 1.4% of total new registrations in 2019 to 2.2% in 2020. Battery electric vehicles, rather than plug-in hybrids, accounted for most electric vehicle registrations in 2020 for cars and vans. [24] Furthermore, the European Parliament has recently agreed to not allow the sale of new non-zero-emissions vehicles starting from 2035 [25].

The study considers:

a) the increased use of electric vehicles in road transport, including electric personal transport (passenger cars, vans and motorcycles), buses and trucks;
b) increased electrification of rail transport (electrification of some current rail lines and Rail Baltic);
c) and electrification of some ferries.

2.5.1. Road transport methodology

It is assumed that the share of distance travelled by electric vehicles is equal to the number of electric vehicles on each year. To find the distance travelled for all cars and vans, buses, trucks, and motorcycles on Estonian roads from 2025 up to 2050 with 5-year increments, the model takes as input historical distance travelled in million km and the change in distance travelled, in % per a 5-year period, for all vehicles during the time-series in these categories. The total number of vehicles in each category for each year is calculated by taking the historical number of vehicles in each category and the change in the number of vehicles, in % per a 5-year period as input.

To find the distance travelled by electric vehicles for each specified year, the model takes as input the share of distance travelled by electric vehicles in each category and multiplies it by the distance travelled by all vehicles in each category. To find the number of electric vehicles for each year, the model takes as input the share of electric vehicles in all vehicles in each category and multiplies it by the number of all vehicles in each category.

Share of all vehicles in each category in each county from 2025 up to 2050 with 5 -year increments is predicted by applying a linear regression using the least squares method. The model takes as input historical and projected population of each Estonian county up to the year 2050, historical data on vehicles registered in each county and dummy variables for the counties. The resulting prediction is translated into percentages of vehicles by category in each county for each year. This prediction is used in combination with previously calculated total number of vehicles in each category for each year to find the number of all vehicles in each category in each county for each specified year. It is assumed that electric vehicles follow the same distribution among counties as all vehicles combined (an exception is the year 2025, where the distribution of electric cars and vans among counties is corrected according to current electric vehicles registration data). It is assumed in the model that total distance travelled in each county is proportional to the number of vehicles in each county.

The split between slow charging in households and fast charging in public charging stations is considered. It is determined in the model using a time-series of percentages of electricity consumed by slow charging in households and in public fast chargers.

The model considers the implementation of non-smart charging, smart charging, and vehicle to grid (V2G) enabled smart charging for cars and vans at households (slow charging). The split between these charging types is determined by a time-series of percentages of electricity consumed by each charging type. The charging profiles for non-smart charging and smart charging are different and have different effect to the peak demand. Smart and non-smart charging have different consumption profiles for workdays and weekends. It is assumed that the profile for fast charging is the same on all days. Because demand is usually not the same year-round, seasonality of consumption is considered with coefficients for each of the twelve months. Separate seasonality coefficients are used for non-smart charging, smart charging and fast charging cars and vans, and motorcycles.

V2G acts as local energy storage, that reduces the energy demand from the network and can be used to provide DSR (demand side response) services to the grid. To determine the available V2G power for each hour of a workday and for weekends, the model takes as input the average charger power, loss on charging and discharging and V2G uptake among all smart charging capable vehicle/charger combinations. To determine, on which days V2G might discharge into the grid, the model takes as input cut-off peak powers (for summer and rest of the year separately) and the power profile of the whole distribution grid.

Average daily electricity consumption in each county for cars and vans is determined by:

$$E_{l,y,c} = \frac{\alpha_{l,y} \cdot C_y \cdot s_y \cdot w_{c,y}}{365}$$

where l is the location (that is county), y is the year and c is the charging type (that is non-smart-charging, smart charging, or public fast charging); $\alpha_{l,y}$ represents the share of distance travelled in a specific county on a specific year, C_y is the efficiency (kWh/km) on a specific year, s_y is the distance travelled on a specific year, and $w_{c,y}$ is the share of a specific charging type on a specific year.

Hourly electricity consumption in each county for cars and vans is determined by:

$$E^t_{l,y,c} = E_{l,y,c} \cdot \alpha_{c,h,d} \cdot \alpha_m$$

where t is an hour of a year, d is the type of day (workday or weekend, not applicable for fast charging), and m is represents the month; $\alpha_{c,h,d}$ represents the share of electricity consumed during an hour of a day for a specific charging type on a workday or weekend and $\alpha_m$is the seasonality coefficient for each month.

Average daily electricity consumption in each county for buses, trucks and motorcycles is determined by:

$$E_{l,y} = \frac{\alpha_{l,y} \cdot s_y \cdot w_y}{365}.$$

Hourly electricity consumption in each county for buses, trucks and motorcycles is determined by:

$$E^t_{l,y} = E_{l,y} \cdot \alpha_{h,d}.$$

2.5.2. Road transport assumptions

The assumptions made for the distance travelled by all vehicles during the time-series in the base scenario are shown in Figure 2.33 and were calculated based on national yearly traffic frequency change coefficients in the base scenario determined in a report by TalTech [26].

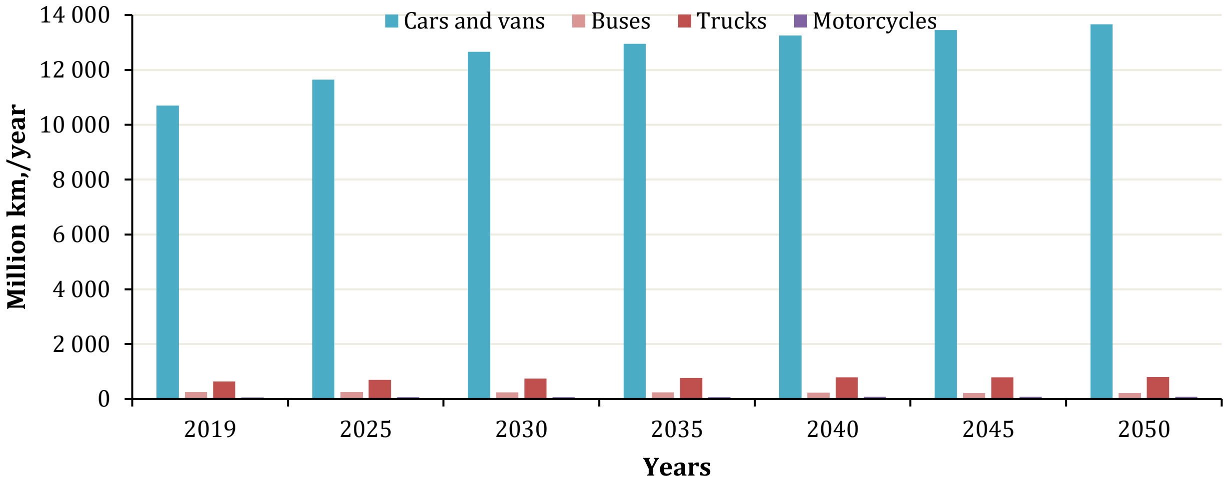


Figure 2.33. Distance travelled of all vehicles

The assumptions made for the number of all vehicles in Estonia during the time-series in the base scenario are shown on Figure 2.34 and are based on car use level change coefficients in the base scenario determined in a report compiled by TalTech [26].

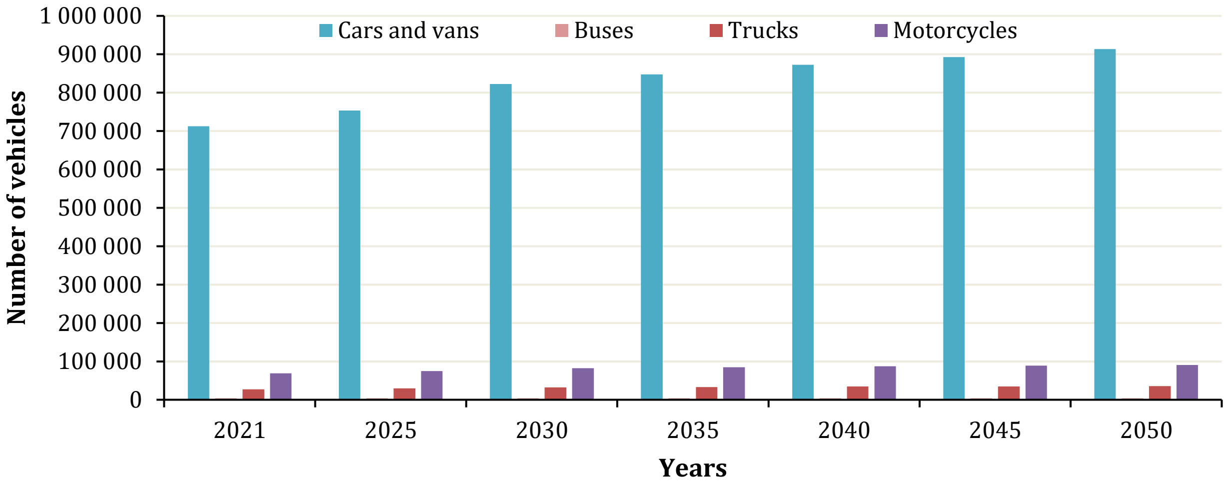


Figure 2.34. Number of all vehicles

The assumptions made for the uptake of electric vehicles as a share of all vehicles in the base scenario are presented in Figure 2.35 - Figure 2.37. The number of electric vehicles during the time-series are presented in Table 2.3. The assumptions for the base scenario are based on research produced by Civitta [14] and adjusted based on feedback from the contracting entity Elering. **It is assumed that the share of distance travelled by electric vehicles is equal to the number of electric vehicles on each year.**

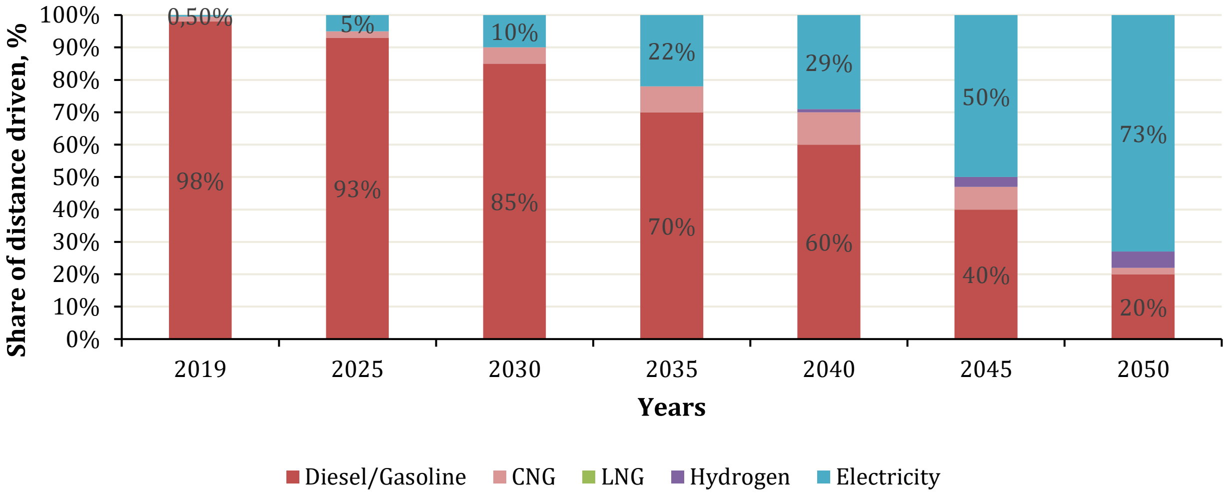


Figure 2.35. Share of distance driven by cars in the base scenario

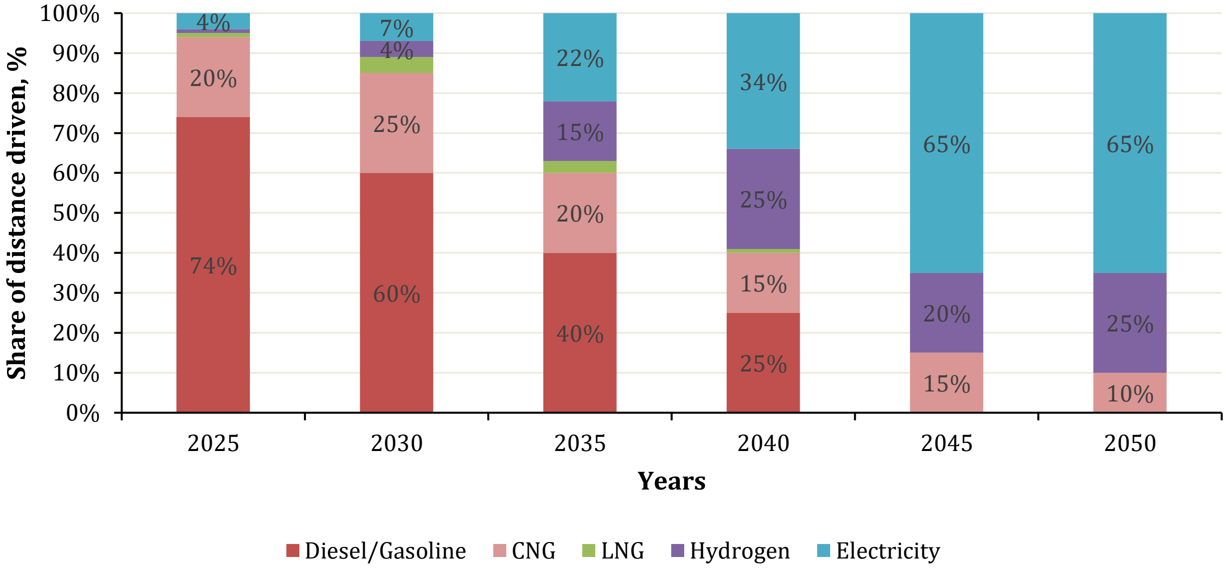


Figure 2.36. Share of distance driven by buses in the base scenario

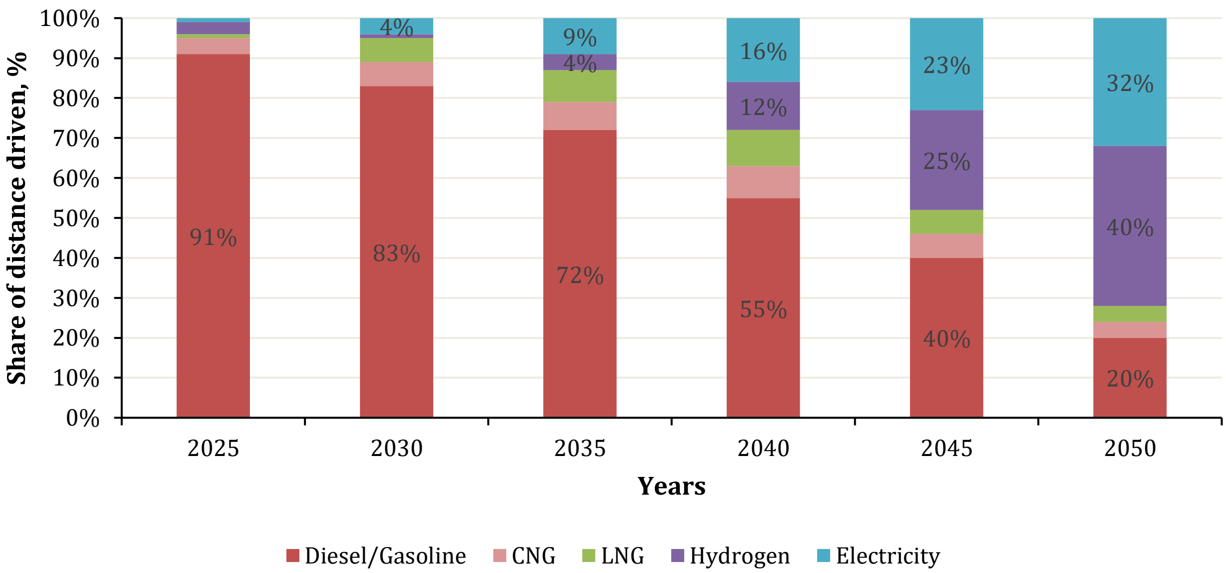


Figure 2.37. Share of distance driven by trucks in the base scenario

Table 2.3. Number of electric vehicles during the time-series

pcs\year	2025	2030	2035	2040	2045	2050
Electric Cars and Vans	37 681	82 273	186 403	253 048	446 417	666 898
Electric Buses	153	262	802	1 208	2 270	2 231
Electric Trucks	296	1 282	2 986	5 495	7 994	11 256
Electric Motorcycles	3 748	8 184	18 542	25 172	44 407	66 339

The spilt between non-smart and smart charging in home charging situations on each year is determined according to Table 2.4. The share of smart charging in 2050 is based on electric vehicle scenarios proposed in the UK [27]. The share of smart charging in 2025 is an assumption. The in-between years are the results of interpolation.

Table 2.4. Non-smart and smart charging split for cars and vans

Type\Years	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
smart	10%	25%	39%	54%	68%	83%
non-smart	90%	75%	61%	46%	32%	17%

Table 2.5 adds public fast charging to the charging split. According to [28], 90% of Norwegian electric vehicle owners daily charge at home. Generally, a larger part of the population of Estonia lives in apartment buildings opposed to single family dwellings than in Norway. Therefore, it is assumed that the share of public fast charging is also larger. The split between different charging solutions is constant for all scenarios.

Table 2.5. Charging split for cars and vans

Type\Years	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
smart	9%	21%	31%	43%	55%	66%
non-smart	81%	64%	49%	37%	25%	14%
fast	10%	15%	20%	20%	20%	20%

The assumptions used for the efficiency of electric vehicles are demonstrated in Table 2.6. The starting efficiency of cars and vans is based on the efficiency used in a Danish study [28], the electricity consumption on following years assumed to decrease 1% per a five-year period. The efficiency of trucks in 2025 and 2035 is based on a report by European Federation for Transport and Environment [29], it is assumed that efficiency of trucks shall stay on a similar level starting from 2035. It is assumed that the efficiency of buses is the same as for trucks. The efficiency of motorcycles in 2025 is based on the example of an electric motorcycle, Zero SRS [30]. As for cars and vans, it is assumed that the electricity consumption decreases by 1% per 5-year period.

Table 2.6. Efficiency of electric vehicles, kWh/km

Category\Years	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Cars and vans	0.240	0.238	0.235	0.233	0.231	0.228
Buses	1.520	1.370	1.210	1.210	1.210	1.210
Trucks	1.520	1.370	1.210	1.210	1.210	1.210
Motorcycles	0.110	0.109	0.108	0.107	0.106	0.105

The hourly profiles used to calculate hourly electricity consumption (Annex 1. Electricity consumption profiles in the transport sector) for cars and vans for non-smart, smart and fast charging, for buses and trucks were provided by the contracting entity Elering. For motorcycles, the hourly consumption profile is assumed to be the same as non-smart charging for cars and vans on workdays. It has been found in a Danish study [28], that there is significant seasonal variation in electricity consumption by electric vehicles. To estimate the seasonality of energy consumption by cars and vans, an assumption has been made for monthly differences in consumption based on the Danish study [28]. As the use of motorcycles is also seasonal, an assumption has been made that the charging of electric motorcycles falls on the period from May to September.

Table 2.7 describes the variables used to model vehicle to grid (V2G) behaviour. It is assumed that home chargers used in Estonia by V2G participants are 11 kW, which is a common EV charger power. The loss row describes a one-directional loss, i.e., charging incurs a 10% loss and discharging incurs a 10% loss as well. The activation of V2G is determined in the model in a simplified manner. Cutoff percentages are used to calculate the required daily peak power for V2G to activate, i.e. for V2G to activate on a certain winter day, that day's peak power consumption must be over 85% of yearly peak power. This results in V2G being activated on days with highest peak consumption values. In real life V2G will rather follow the electricity market price signals, but as electricity price modelling is not in the scope of study a simplified approach was used. It is assumed that higher winter peak demands will result in a higher electricity price, thus it's more likely that V2G capability will be activated to shift consumption from the expensive peak hours to more affordable hours. In the summer periods cheap PV electricity production will allow for storing solar energy in EV batteries. The potential share of V2G uptake of all smart charging is assumed to be 26% by 2050, the assumption is set by example of energy scenarios of the UK [27]. Years from 2025 to 2050 are determined by linear interpolation and assuming that in 2025 V2G uptake is still at 0% as it is a relatively new technology. V2G assumption is constant for all scenarios.

Table 2.7. Vehicle to grid input variables

Variable\Years	2025	2030	2035	2040	2045	2050
Charger, kW	11	11	11	11	11	11
Loss, %	10%	10%	10%	10%	10%	10%
Cutoff summer, %	56%	56%	56%	56%	56%	56%
Cutoff winter, %	85%	85%	85%	85%	85%	85%
V2G share of smart charging, %	0%	5%	10%	16%	21%	26%

The assumptions for the share of electric vehicles plugged in (Figure 2.38) on each hour of a workday or weekend and available flexible power of an EV fleet (Figure 2.39) on each hour on a workday or weekend (Annex 1. Electricity consumption profiles in the transport sector) was estimated based on the data collected in the Electric Nation project [31] in the UK. The share of plugged-in vehicles tends to differ during workdays and weekdays, so different profiles are used. In addition, the entire charging power of each connected vehicle is never available for providing V2G services, for example, batteries may require recharging for driving purposes and are not available for V2G. Hence, the percentage of flexible power represents the share of a connected fleet's nominal power that can be used for V2G purposes, which represents the percentage of charger power available for providing energy from EVs to the grid. This share is a proportion of all the cars connected to the grid at that time.

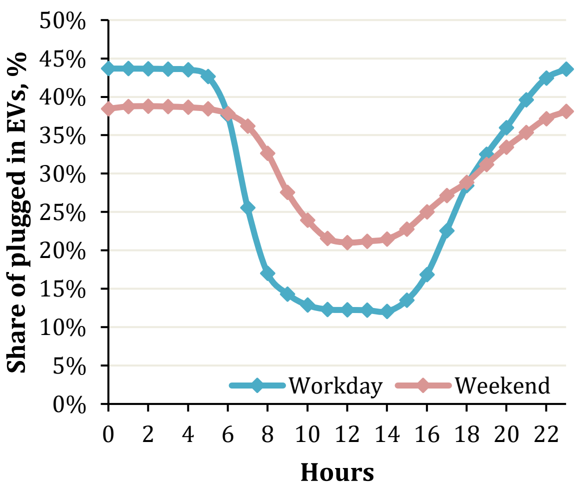


Figure 2.38. Hourly share of plugged in EVs

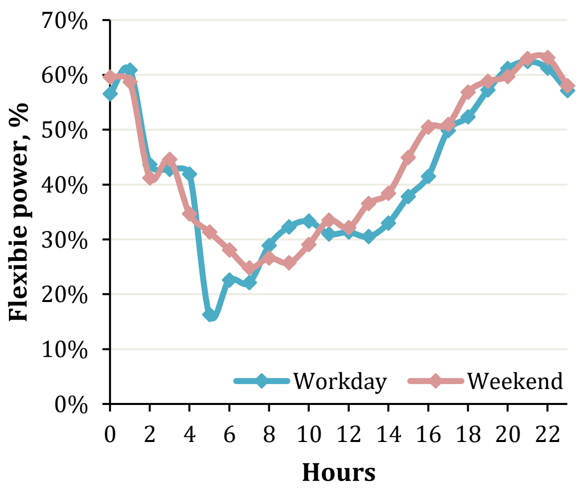


Figure 2.39. Flexible power of plugged-in EVs

Figure 2.40 describes how much the fleet of vehicle-to-grid capable vehicles were able to maximally shift demand per hour during each year of the time series. However, it must be noted that in the model V2G, considering the assumptions, V2G was activated on 30-40% of the days of the years. In the real world, a certain price difference for charging and discharging is required for the system to activate. As a simplification, for the purposes of this study, the model assumes that it is reasonable for V2G capable vehicles to charge when demand is lower and discharge when demand is higher.

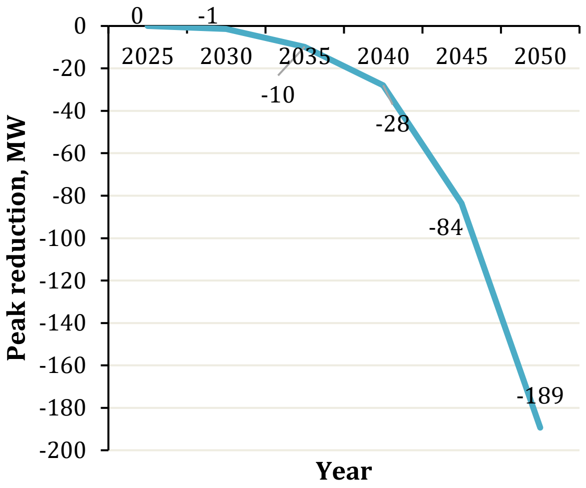


Figure 2.40. Peak reduction by V2G

2.5.3. Rail transport methodology

The model for future passenger rail electricity consumption takes as input the energy efficiency of passenger trains, historical train kilometres on different lines within Estonia, the projected overall changes in train-km and changes in train use in the main directions of train travel in Estonia, as projected by the ITF [13], electrification status of the lines until 2050 and the locations of the railways within Estonia and returns the projected electricity consumption in each county from 2025 up to 2050 with 5-year increments.

Yearly passenger train electricity consumption on each train line each year is determined by:

$$E_{line,y} = C_y \cdot s_{line,y} \cdot \beta_{line,y}$$

where $line$ represents the specific train line; C_y is the efficiency of passenger trains (kWh/train-km), $s_{line,y}$ is the distance in train-km for each line for each year, and $\beta_{line,y}$ is a binary variable (0 or 1) representing the electrification status of each line for each year.

Average daily electricity consumption in each county for passenger trains is determined by:

$$E_{l,y} = \left. \left(\sum_{line} E_{line,y} \cdot \frac{\beta_{line,l}}{\sum_{line} \beta_{line,l}} \right) \middle/ 365 \right.$$

where $\beta_{line,l}$ represents a binary variable about the existence of a railway in a specific location l (i.e., county).

Hourly electricity consumption in each county for passenger trains is determined by:

$$E_{l,y}^{t} = E_{l,y} \cdot \alpha_h$$

where α_h is the share of electricity consumed during an hour of a day.

Hourly electricity consumption in each county for electric freight trains (on Rail Baltic) is determined by:

$$E_{l,y}^{t} = \frac{F_y \cdot C_y \cdot \alpha_{l,y}}{365} \cdot \alpha_h$$

where F_y represents yearly freight flows on electric railways (million tonnes), C_y is efficiency (kWh/tonne-km), $\alpha_{l,y}$ is the share of electricity consumed in each location (i.e., county) on each year.

2.5.4. Rail transport assumptions

The main assumption of freight transport on railways (Table 2.8) is the amount of freight transported during the time-series, which is based on the projection by EY [32]. However, in the model, the freight flows have been shifted into the future compared to EY's projection, as the Rail Baltic project has experienced some delays. The energy consumption of freight trains on Rail Baltic is based on the analysis by Piterina and Masharsky [33]. Railway length is the length of Rail Baltic specifically within Estonia. Electricity consumption is equally divided between Harju county (Järveküla substation [34]), Pärnu county (Kabli and Kilingi-Nõmme substations [35]) and Rapla county (Kehtna substation [36]).

Table 2.8. Freight rail (Rail Baltic) assumptions

Variables\Years	2025	2030	2035	2040	2045	2050
Freight, million t	0	5.1	5.45	5.8	6.1	6.4
Railway length, km	0	213	213	213	213	213
Electricity use, kWh/tonne-km	0	0.05	0.05	0.05	0.05	0.05
Freight, million tonne-km	0	1088	1162	1237	1301	1365
Electricity use, GWh/y	0	54.4	58.1	61.8	65.0	68.2

Table 2.9 consists of two parts, an assumed overall change in train-km by passenger trains and an additional increase in different lines separately, which are based on a study by the ITF [13]. Efficiency (electricity use per train-km) is calculated based on historical energy consumption data by Statistics Estonia [37] and train-km data by Ministry of Economic Affairs and Communications [38]. Hourly consumption profile for passenger trains was provided by the contracting entity Elering.

Table 2.9. Passenger railways, change in distance travelled per 5-year period, %

	2025	2030	2035	2040	2045	2050
Overall	8%	17%	25%	33%	42%	50%
Harju	16,5%	33,0%	49,5%	66,0%	82,5%	99%
E-W, Tallinn to Narva	4,7%	9,3%	14,0%	18,7%	23,3%	28%
N-SE, whole line, Tallinn to Valga/Koidula	2,2%	4,3%	6,5%	8,7%	10,8%	13%
N-SE, Tallinn to Tartu only	2,3%	4,7%	7,0%	9,3%	11,7%	14%
N-SW, Tallinn to Pärnu/Viljandi	7,3%	14,7%	22,0%	29,3%	36,7%	44%

2.5.5. Ferry transport methodology

Ferry transport model takes a top-down approach and distributes the projected annual energy consumption with an hourly resolution using hourly consumption profiles, seasonality coefficients and weekly variation (which is different for summertime and the rest of the year).

Hourly electricity consumption for each ferry line for every year is determined by:

$$E_{line,y}^{t} = E_{line,y} \cdot \alpha_{line,d,h} \cdot \alpha_{m,wd}$$

where $line$ is a ferry line, d is the type of day (workday or weekday), m is the month (from 1 to 12), and wd is the day of the week (from 1 to 7).

2.5.6. Ferry transport assumptions

It is assumed that only the Virtsu – Kuivastu line shall be electrified; half of all ferry trips on the line shall be operated by an electric ferry starting from 2045 and all trips on the line shall be electrified from 2050. Hourly electricity consumption profiles are based on usual workday and weekend schedules of the line [39]. Seasonality (monthly differences) coefficients have been calculated based on historical fuel consumption data of the line. Weekly variation coefficients have been determined from average trips each weekday on a summer week and a non-summer week.

2.5.7. Transport summary

The assumptions made for the change in distance travelled by all vehicles for the change in the number of all vehicles during the time-series are shown graphically on Figure 2.41 - Figure 2.48. The change in distance travelled by all vehicles per a 5-year period is based on national yearly traffic frequency change coefficients determined by Tallinn University of Technology (TalTech) [26]. The change in the number of all vehicles during the time-series is based on car use level change coefficients determined by Tallinn University of Technology. For all road transport modes, except buses, a slight drop-off of the increase of demand is expected due to the likely reduction in population and/or taxation policy, however projections further than 10 years have a substantial uncertainty [26].

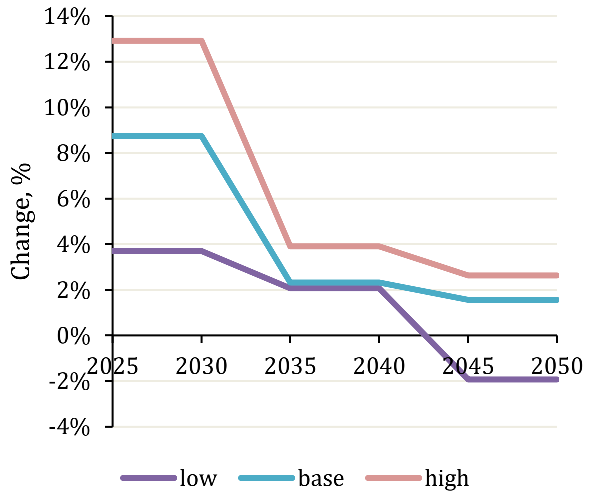


Figure 2.41. Cars and vans travel distance scenarios

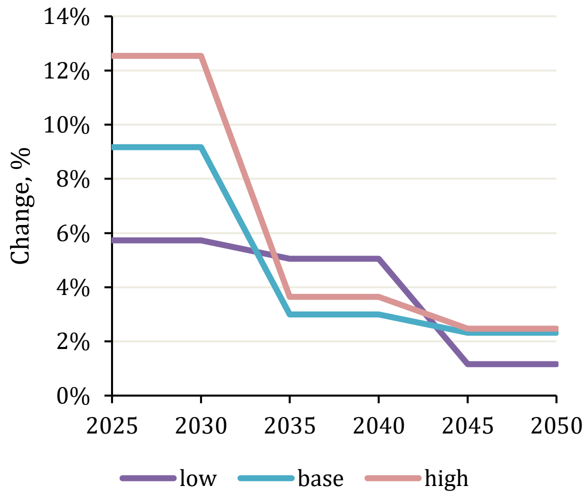


Figure 2.42. Number of cars and vans scenarios

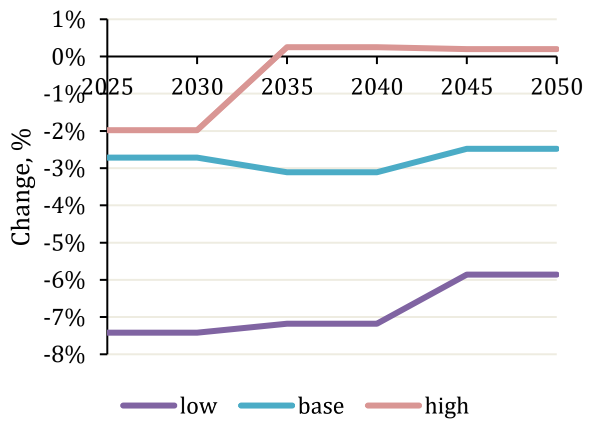


Figure 2.43. Buses travel distance scenarios

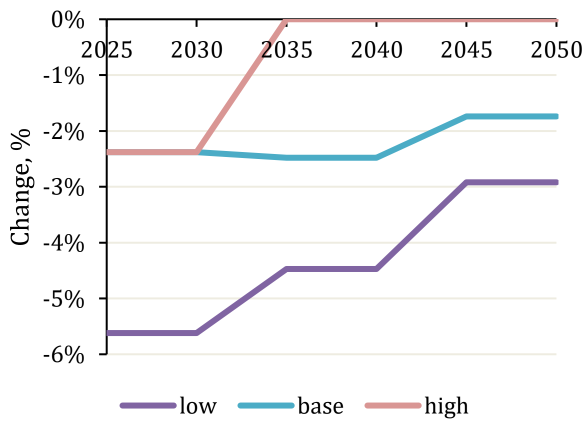


Figure 2.44. Number of buses scenarios

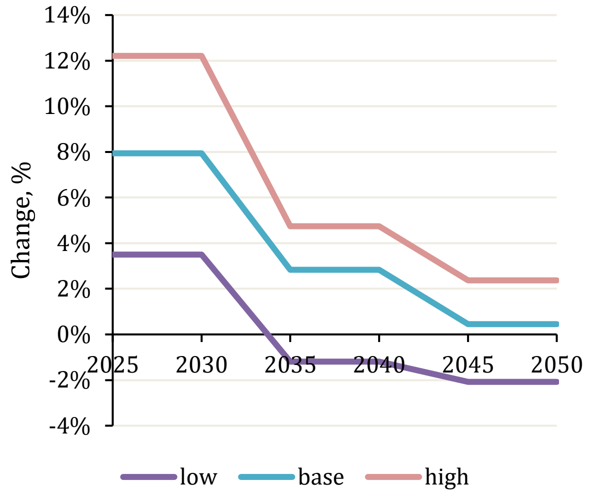


Figure 2.45. Trucks travel distance scenarios

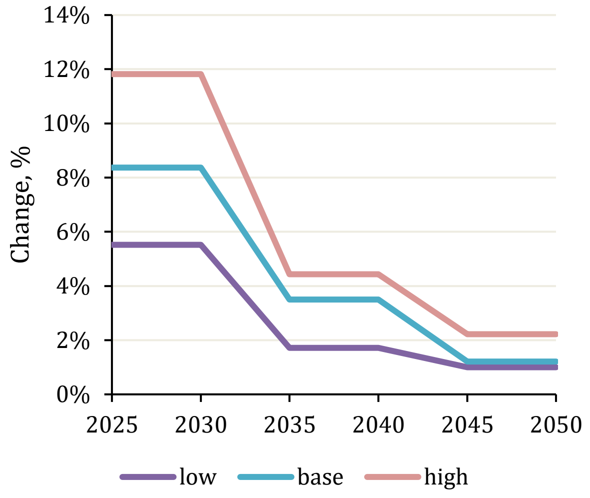


Figure 2.46. Number of trucks scenarios

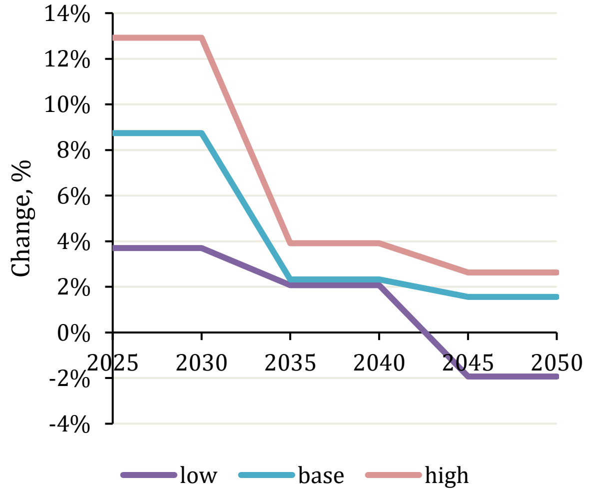


Figure 2.47. Motorcycle travel distance scenarios

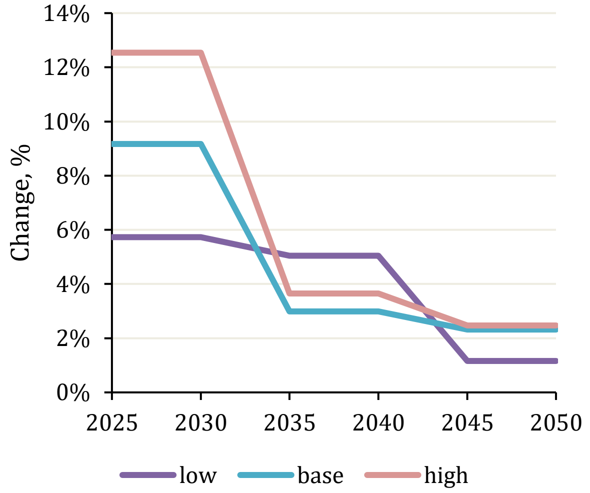


Figure 2.48. Number of motorcycles scenarios

Figure 2.49 – Figure 2.50 describe the effect of transport sector electrification on overall yearly electricity demand and peak consumption. Clearly, road transport is going to have the most significant effect on the electricity grid. The effect of further electrification of rail and ferry sectors has a much smaller effect on overall consumption, at least given the assumptions specified in this study.

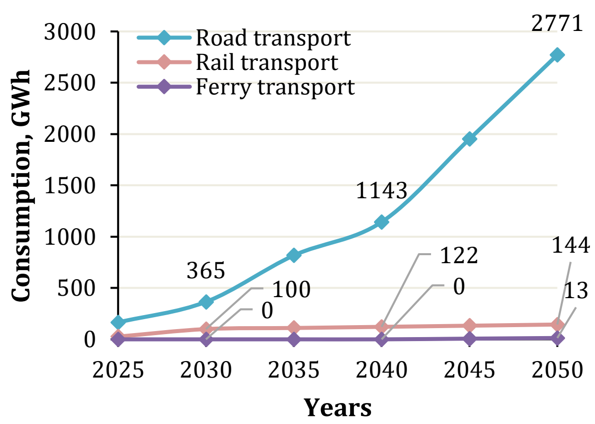


Figure 2.49. Electricity demand of the transport sector (base scenario, with V2G)

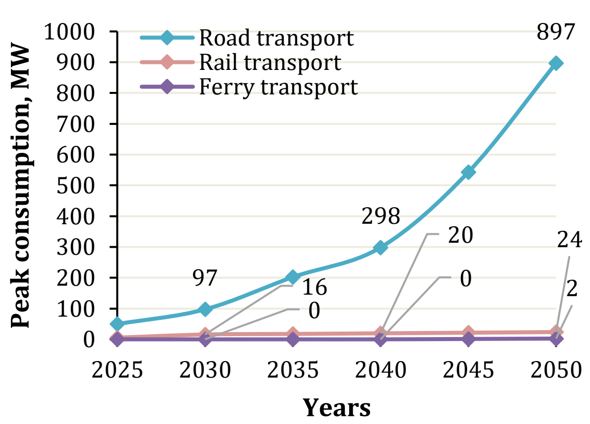


Figure 2.50. Peak consumption of the transport sector (base scenario, with V2G)

3. Model results

3.1. Model's structure

Electricity demand scenarios are composed of two main parts:

- Baseline demand, which is based on a linear regression analysis of historical electricity demand, weather data and other data.
- Additional trends affecting the future of electricity demand, including the electrification of district heating, electrification of natural gas use, renovation of buildings, increasing solar power capacity and the electrification of the transport sector.

Baseline demand analysis quantifies general trends in power consumption arising from economic growth, climatic factors, small shifts in user preferences etc. However, it is also important to consider additional trends, as these are influenced greatly by energy efficiency and climate policy which cannot be estimated by the regression model. These sectors specifically are important as they have been determined to see significant change in the period until 2050.

Electricity demand is assessed on three levels:

- **Level 1: end user demand without local generation.** On this level local production (solar power generation) and vehicle to grid is not considered.
- **Level 2: distribution network demand** (end user demand with local generation)**.** This level adds local generation from solar panels on buildings to reduce demand and vehicle to grid solutions.
- **Level 3: transmission network demand**. This level also considers additional electricity generation from distribution networks, so large distinct solar farms. Power generation in the transmission system network is not in the scope of this study.

Each of the levels are also estimated in three distinct scenarios: base, low and high. All the calculations are based on the base scenario. In the low scenario, relevant assumptions have been shifted to project a lower possible electrification level, i.e., it is a more pessimistic scenario. The high scenario projects a more rapid rate of electrification and an increase in electricity consumption. The assumptions for each scenario have been described in Paragraph 2.

The model was created in MS Excel. Model's logic map with different file and sheet names are depicted on Figure 3.1. Different sector model files calculate hourly load profiles for 110kV substations. Results files combine sectors' results and calculate electricity demand scenarios providing yearly energy demand values and peak power values both annually and hourly.

Hourly energy demand is divided between the substations by weights which are calculated based on the historical data. Annual energy consumption is divided into sectors using historical sector data and changes.

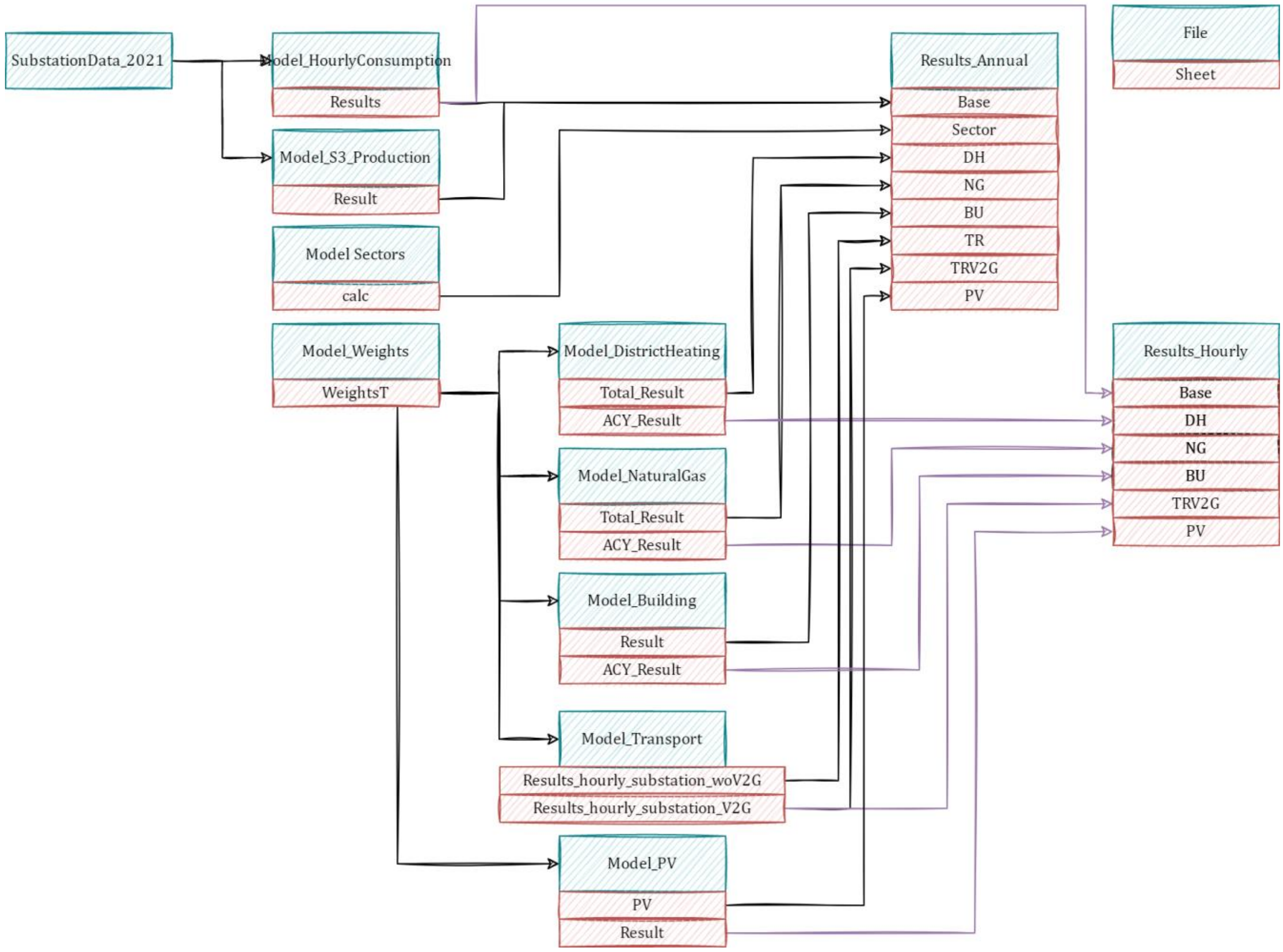


Figure 3.1. Model's logic map

3.2. Aggregated results

Level 1 consumption, i.e., **end consumer demand without local generation or generation in the distribution networks**, in the base, low and high scenarios for average climate year is described in the flow chart (Figure 3.2). Base scenario demand is demonstrated as a stacked bar graph, and total consumption levels for low and high scenarios are shown as lines on the graph. While there is an increase of electricity use in all sectors, it is expected that the transport sector will comprise around half of the increase in electricity consumption. Overall, electricity consumption is expected to be steadily increasing until 2050. Although energy efficiency is constantly increasing, which does reduce energy consumption in some respects, the effects of economic growth and the electrification of large sectors of energy consumption on electricity consumption is much greater, which is projected to increase electricity demand greatly in the coming years.

The lower and higher demand, respectively, of the low and high scenarios, stems from different assumptions made in the projections. For district heating electrification different levels of electrification are considered. For natural gas use electrification, low electrification scenario expects natural gas to be replaced with other alternative fuels, whereas high electrification prioritizes electricity. In the building sector, different rates of renovation are considered. For the electrification of transport, the assumptions effecting demand are divided into two main groups. Firstly, in base, low and high scenarios, different levels of vehicle use (number of vehicles and distance driven), including fossil fuel powered vehicles, is considered, this considers the general attitude and policies concerning personal vehicles and road transport. Secondly, different rates of electric vehicle adoption are considered.

Figure 3.3 describes base scenario electricity consumption on average climatic years (ACY) in the base scenario during 2030, 2040 and 2050 on all the studied consumption levels, where level 1 is end user electricity demand without local power generation (rooftop solar and solar farms power generation is not considered, vehicle-to-grid is not considered); level 2 is end user demand with local generation (rooftop solar power generation and vehicle-to-grid are considered); level 3 is transmission network demand (all solar power, vehicle-to-grid and district heating electrification are considered). As can be seen on the graphs, the difference in demand between the different levels of demand is continuously increasing. This can be expected mainly by the fact that the importance of solar power is going to increase in the future for Estonia and the EU due to current and expected energy policy.

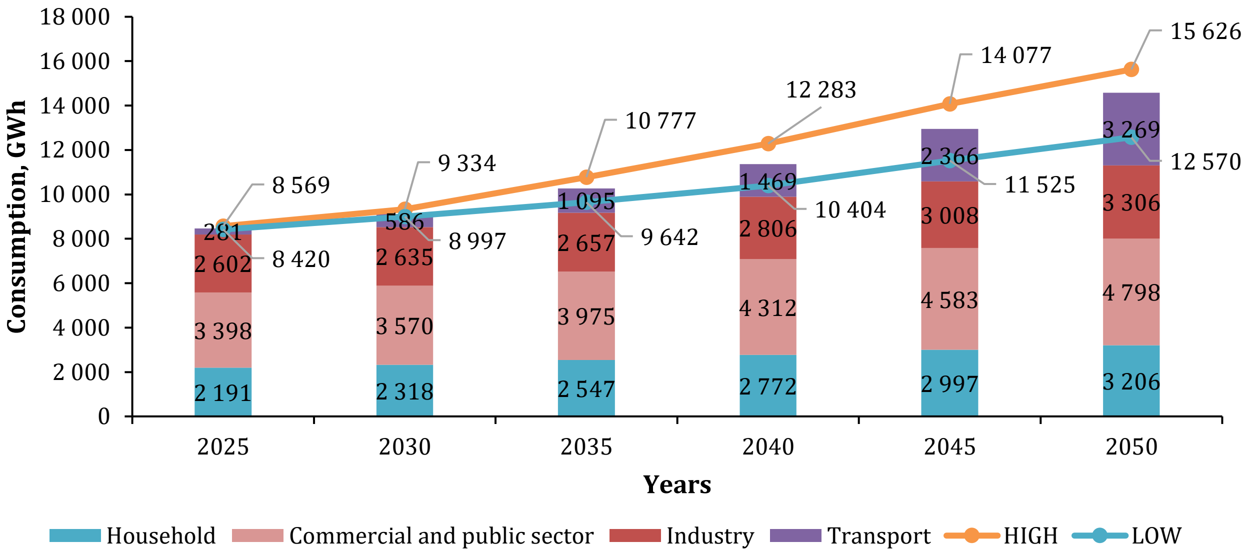


Figure 3.2. Average climate year end consumer consumption

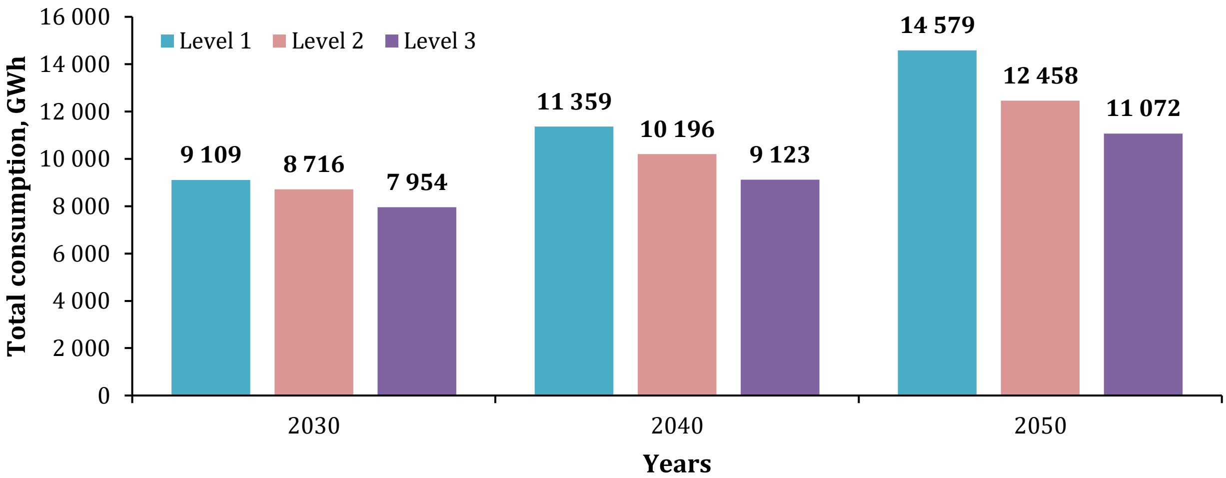


Figure 3.3. Total consumption in the base scenario (ACY) on all consumption levels

The following graphs (Figure 3.4 - Figure 3.5) describe Level 1 overall peak hourly demand and peak demand in summer during extreme climate years (ECY) from 2025 to 2050. Figure 3.6 and Figure 3.7 describe Level 3 peak demand during extreme climatic years. The ECY used in the graphs has a cold winter and a cold summer. The figures include demand projections for the base scenario, low scenario, and high scenario.

Peak energy consumption is going to rise consistently during the years and in summer and winter. The actual transmission network demand (Level 3) is likely to be lower than end user demand (Level 1), if there is available production (e.g., solar panels) or storage capacity (that can shift the demand) on the end consumers' side or in the distribution network. As peak demand is expected to nearly double during the considered time series, it is going to be an important consideration for electricity grid operators in the future, how to best deal with it.

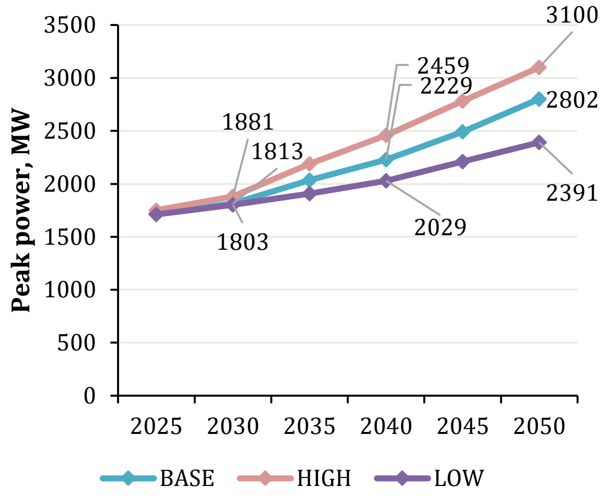


Figure 3.4. Level 1 ECY hourly peak power

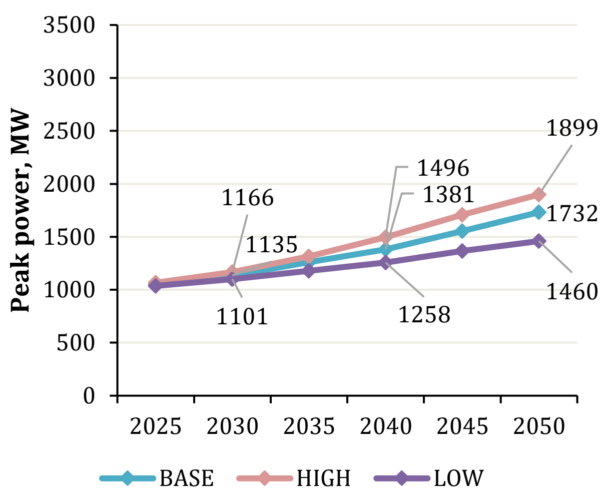


Figure 3.5. Level 1 ECY summer hourly peak power

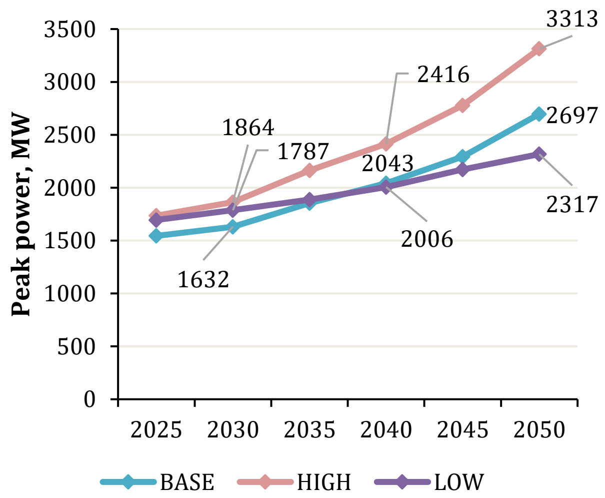


Figure 3.6. Level 3 ECY hourly peak power

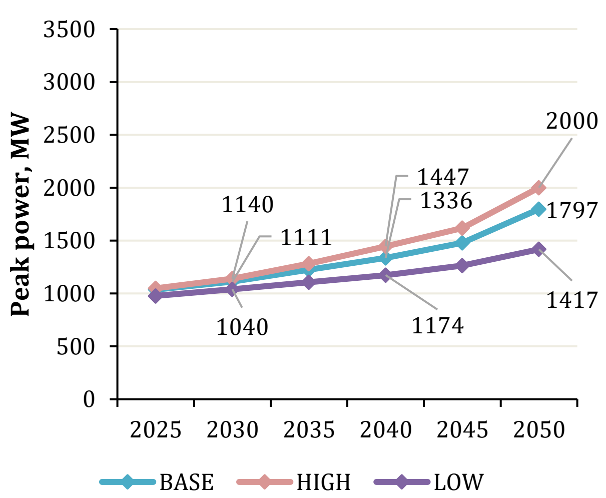


Figure 3.7. Level 3 ECY summer hourly peak power

The distribution of the consumption of different consumers during ACY base scenario can be seen on Figure 3.8. Solar panels give power into the grid and thus are subtracted from the level 1 value to give the total for level 3. The consumption contributed by buildings, natural gas and transport will encompass a larger share of the whole, most of which can be covered by PV energy generation.

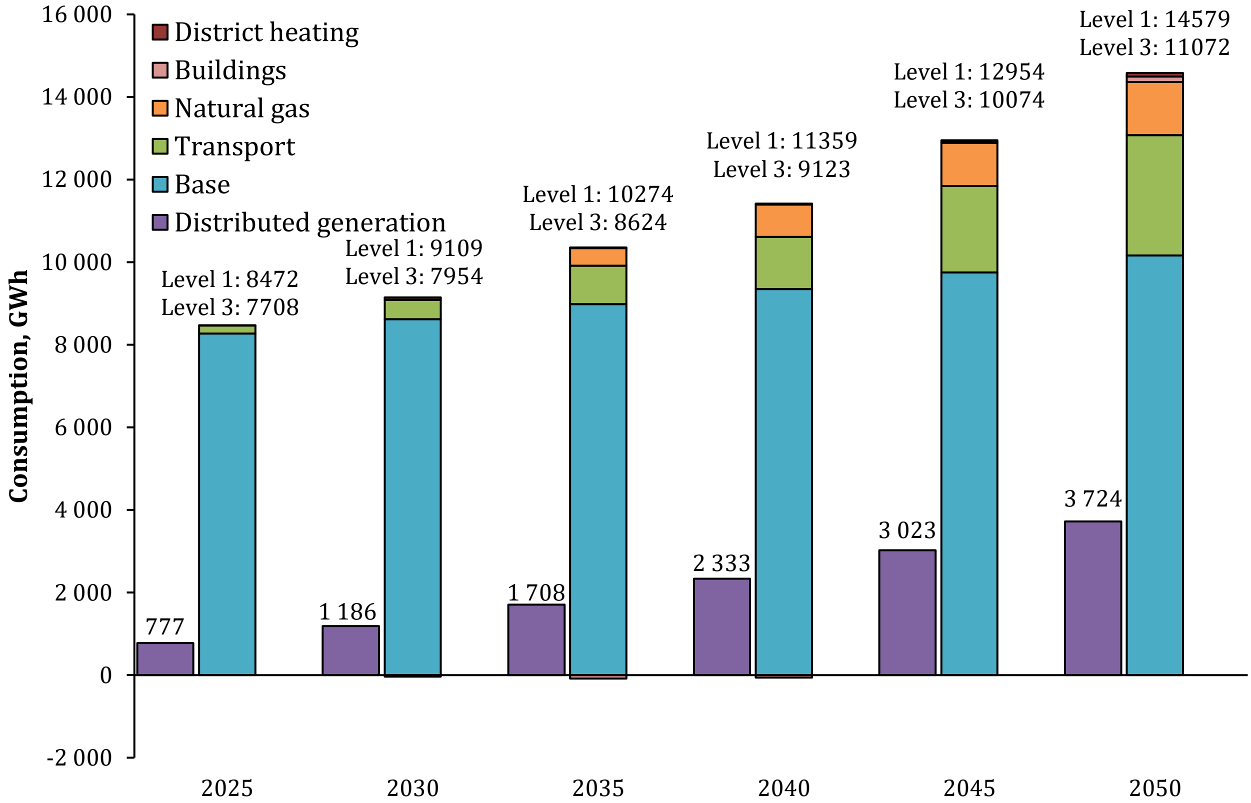


Figure 3.8. ACY base consumption by consumer type

Figure 3.9 shows the distribution of the consumption of different consumers during an extreme climatic year during base scenario. The overall picture is similar with slightly higher consumptions visible. The impact of the growth of different sectors is in general larger than the effect of climate on consumption.

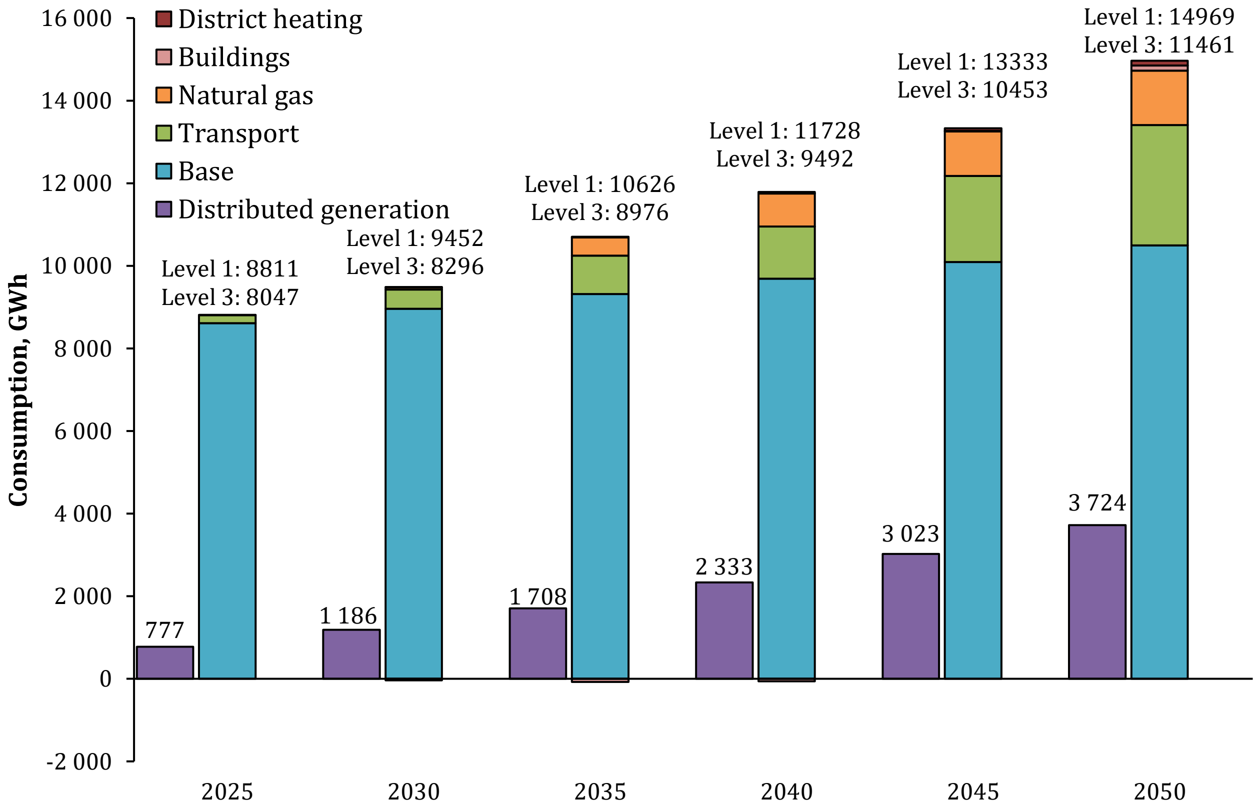


Figure 3.9. ECY base consumption by consumer type

Comparing the average summer weekday consumptions for level 1 and level 3 ACY, the distribution of the PV generation becomes apparent: the overall energy consumption rises though the daily extremes will increase (Figure 3.10 and Figure 3.11). During daytime, the PV panels output more energy than can be immediately consumed, which will encourage the introduction of electricity storage technologies like batteries, power to hydrogen and vehicle-to-grid solutions for electric vehicles or the use of electric boilers in district heating networks. This in turn will help to stabilize prices on electricity markets. A large contributor to increased peaks during evening and night are electric vehicles, which are likely to charge during that period.

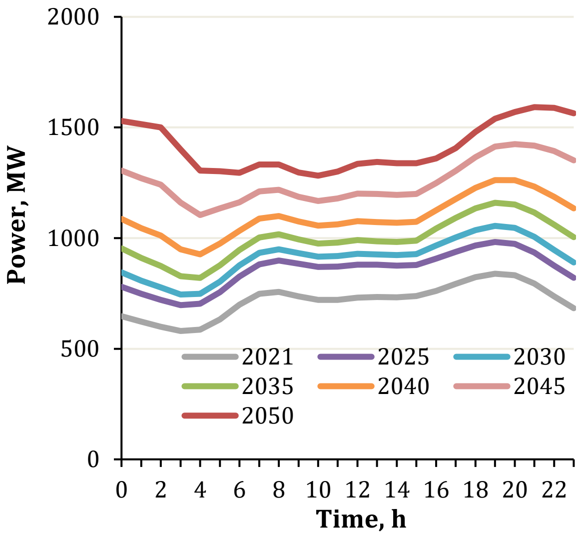


Figure 3.10. Level 1 ACY base summer weekday

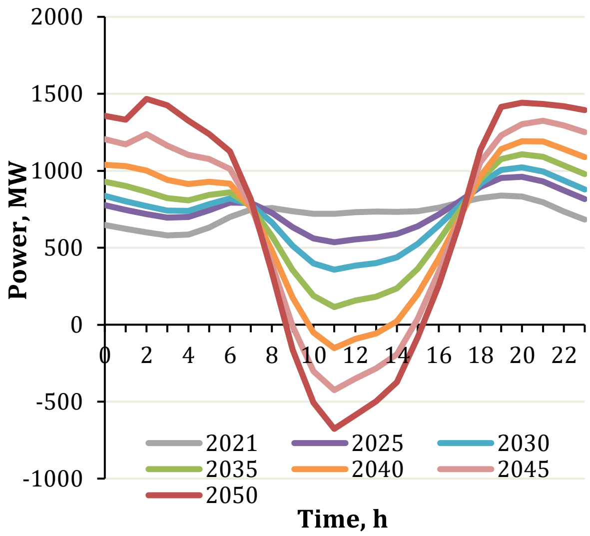


Figure 3.11. Level 3 ACY base summer weekday

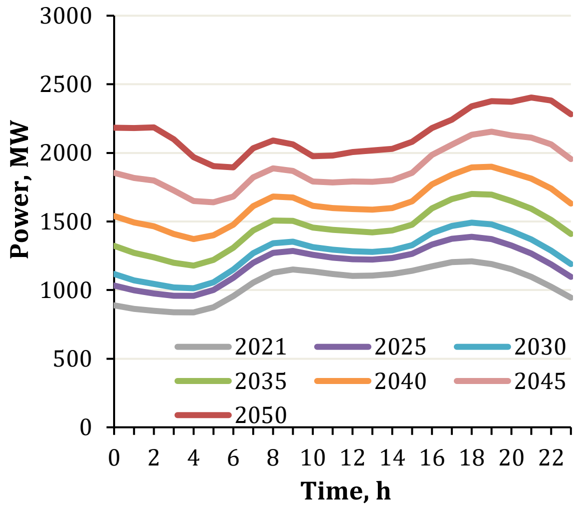


Figure 3.12. Level 1 ACY base winter weekday

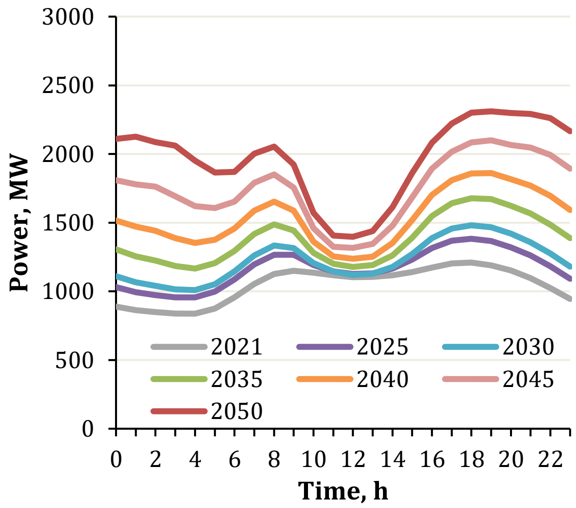


Figure 3.13. Level 3 ACY base winter weekday

Figure 3.12 and Figure 3.13 show that the consumption will be higher in winter and increase steadily till the studied period of 2050. In the winter, solar panels will produce less energy than in the summer due to the reduced amount of sunlight available, which results in a more stable power consumption profile during the winter months.

The average weekly consumption can be seen on Figure 3.14 and Figure 3.15. Not considering solar energy generation, the consumption will increase during all times. With solar energy, the load profile of the average week will also become more extreme, more so in the summer and less in the winter. The given figures represent a yearly average and thus are closer to the autumn or spring.

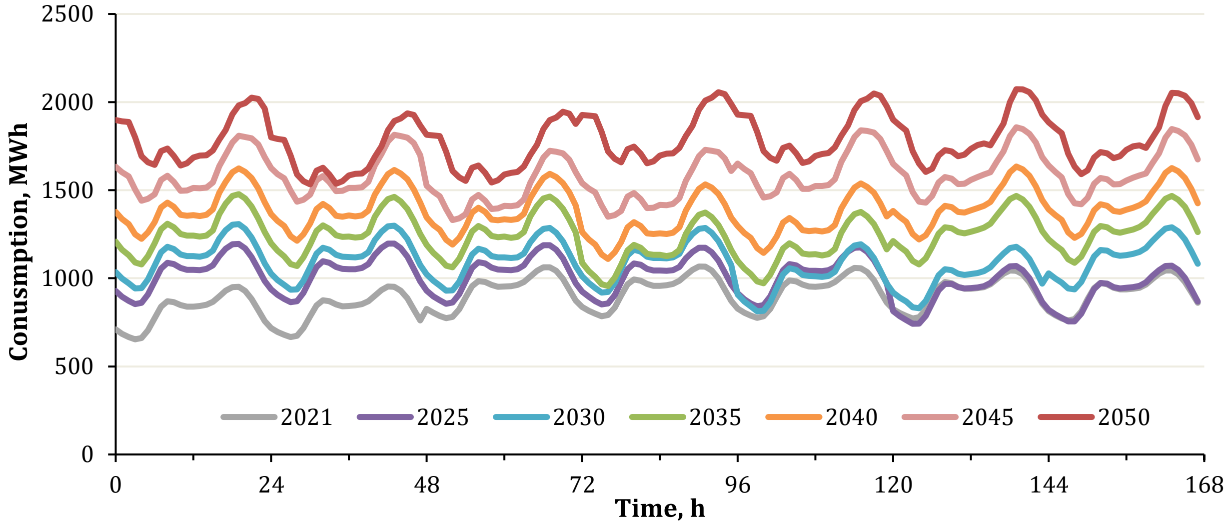


Figure 3.14. Level 1 ACY base average week

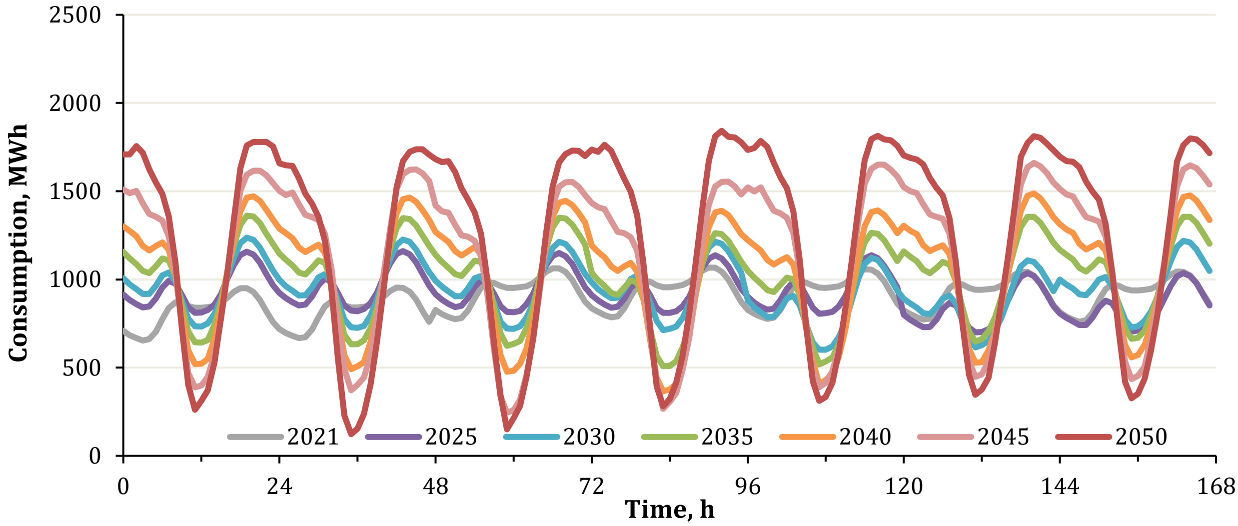


Figure 3.15. Level 3 ACY base average week

On a yearly scale, the consumption can reach over 2500 MWh in the base scenario on level 1 with PV generation lowering it just below the 2500 mark at level 3 (Figure 3.16 and Figure 3.17). In the summer months the average daily transmission network consumption remains at a similar level in 2050 compared to 2021 with the increase in energy demand being visible on level 1. The plateau in consumption during the summer months at both levels can be explained by the drop in the need for heating.

Figure 3.16. Level 1 ACY base year

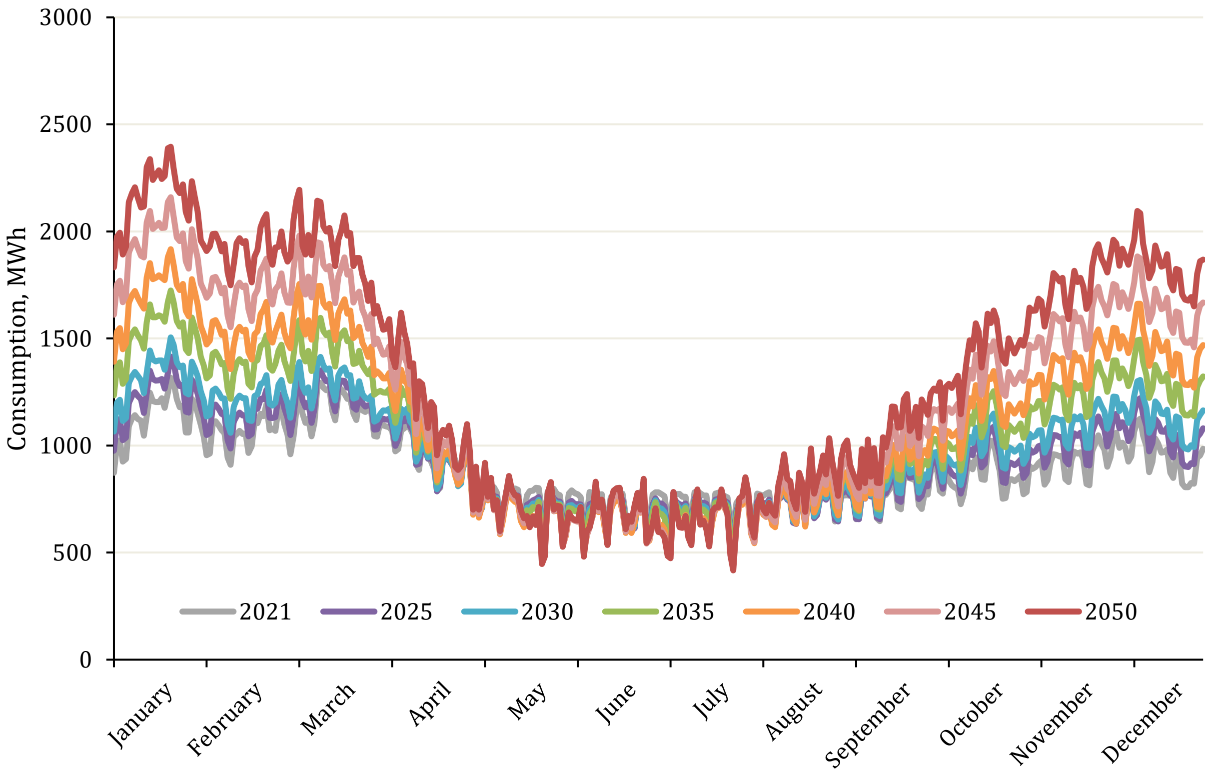


Figure 3.17. Level 3 ACY base year

4. Factors affecting the demand

In this chapter, the effect of different factors and technologies that influence the expected electricity demand and peak power are considered. In addition to factors that are considered in the demand scenarios, other load factors or technologies that are not considered in the electricity demand scenarios, but could possibly affect Estonian electricity consumption, are considered in this chapter as well.

4.1. Demand side response potential

Demand side response (DSR) enables intelligent energy use. Through DSR services, businesses and consumers can turn up, turn down, or shift demand in real-time, which can help soften peaks in demand and fill in the troughs, especially at times when power is more abundant, for example when solar power generation is high. DSR is an important tool to help ensure a secure, sustainable and affordable electricity system. [40] DSR is not used in a very large scale, however first projects exist already even in Estonia. For example, the company Fusebox already provides services to Elering to balance the electricity grid. [41] For business and consumers, DSR is a smart way to save on total energy costs and reduce their carbon footprint.

During 7.12.2021 8.00-9.00 while electricity spot price reached 1000 €/MWh the consumption decreased by 130,7 MWh in Estonia, which is approximately 9% of Estonia's electricity consumption during that hour. [42] In 2014 TalTech analysis indicated 214-407 MW demand side response potential per hour. Table 4.1 shows the distribution of the demand side response potential per hour in Estonia. Even though households have the highest potential, household electricity consumption has high seasonal variability, and the consumption needs to be pooled. In service and industry sector the seasonal variability of consumption in less significant. [43]

Table 4.1 Estonia's demand side response potential by sector [[43]

Sector	Available power per hour, MW
Industry	65
Office buildings 24/7	14
Office buildings 8/5	72
Shopping centres	7-26
Households	55-230
Total	213-407

Demand profiles and therefore the DSR capacity of buildings were created based on minimum requirements for energy performance of buildings [18]. Typical building use parameters for the buildings that are to be renovated during 2025-2050 were used. The analysis focused on device energy consumption. The building demand profile for different sectors is seen on Figure 4.1. Combined capacity and demand profile of public, private and local government buildings is seen on Figure 4.2. Demand profiles are highly correlated with high electricity market prices. Figure 4.3-4.6 represent the power consumption of devices used in the buildings in 2030 and 2050.

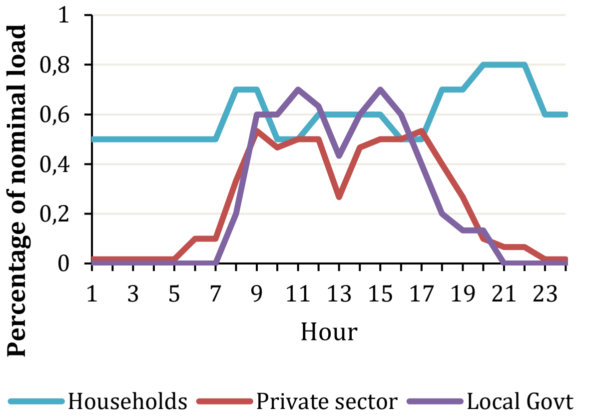


Figure 4.1. Demand profiles for different sectors

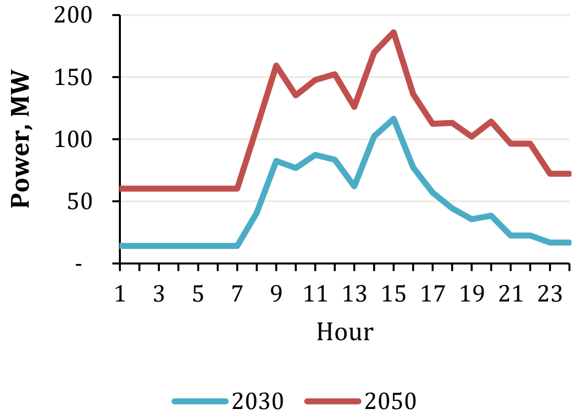


Figure 4.2. Combined capacity of building DSR

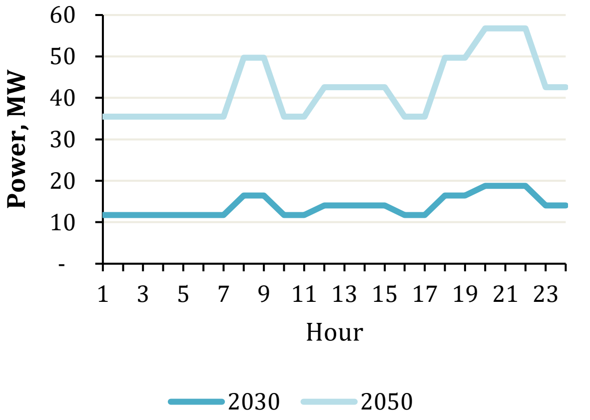


Figure 4.3. Flats demand profile

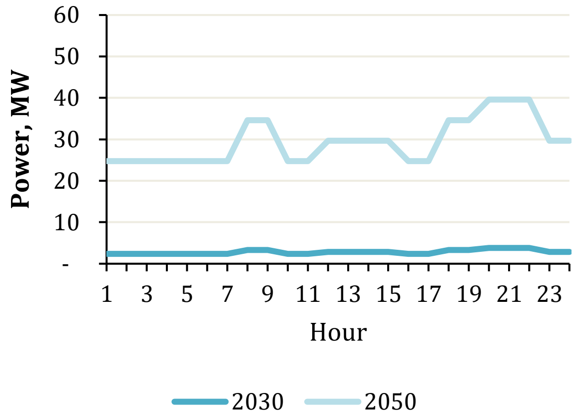


Figure 4.4. Households demand profile

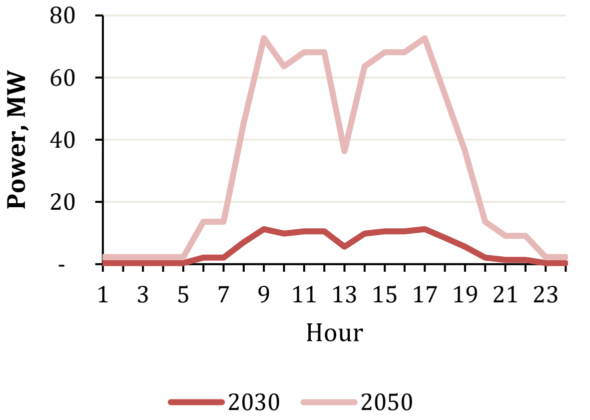


Figure 4.5. Private sector demand profile

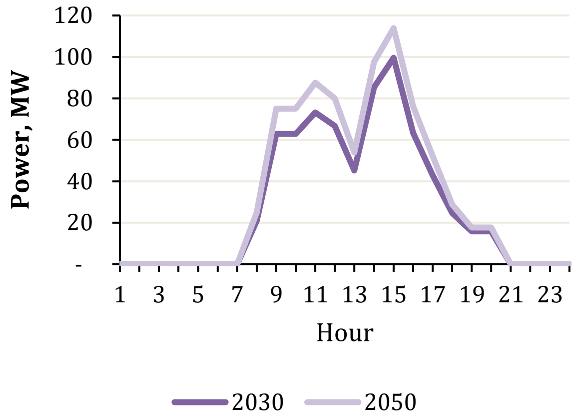


Figure 4.6. Local govt sector demand profile

Based on a Lithuanian study only roughly 20-30% of large users have the technical capacity to alter electricity use. 15-23% of users with an installed capacity of 1-10 MW and 0,1-1 MW have the technical ability to alter their consumption patterns and to deliver ancillary services would have to be pooled. According to the study smallest legal users and households have the highest willingness to provide demand response services – 40-53% according to price variation and 30-63% upon request from a regulator. One of the key takeaways from the study was that end-users are willing to alter their behaviour if it is technically possible to do so without altering their welfare or they are compensated for the flexibility. For households it is important to assure both economic benefits and that the end-user comfort will not be affected, for non-households showing just cost effectiveness is enough [44]. Non-commercial consumers will likely be on the market whenever they have the capability regardless of the electricity price.

In the future electric vehicles (EV) with vehicle to grid (V2G) capability allow EVs to provide electricity to the grid if necessary. It is assumed that almost 1800 vehicles by 2030 and 250 000 vehicles by 2050 with V2G capabilities are in use. This means that by 2030 depending on the hour there is 0,1-0,8 MW of available capacity and by 2050 the available capacity by hour has reached 15,4-110,2 MW (this estimate is based on the methodology and results described in Paragraph 2.5 Transport electrification).

The CAPEX and fixed operating & maintenance costs for V2G are effectively zero, as the vehicles are never purchased for the express purpose of providing DSR services. Variable cost for V2G consists mainly of the cost of a battery replacement for the vehicle. For example, the battery pack of a popular electric vehicle, Tesla Model 3, has a capacity of 75 kWh and is rated for about 1500 charge cycles, although after the rated number of cycles, the battery has probably still about 80% of capacity remaining, so the battery is far from unusable at that point. Moreover, one charge cycle is defined as one full charge and one full discharge of a battery. The battery has a replacement cost of around 17 000 €, so the variable cost for V2G is about 76 €/MWh.

The electricity demand model predicts that, in the base scenario, generation capacity in the distribution grid shall transmit 51 MWh of electricity to transmission grid peaking at 26 MW by 2030. Estonian Environmental Investment Centre is planning to support 20 MW of electricity storage investments [45]. by 2027. Therefore, reverse flow to the transmission network from the distribution grid can be stored by electricity storage solutions instead or be sold to energy markets. However, by 2050 distribution grid is expected to have an excess of 384 GWh of energy available to be transmitted to the transmission system peaking at 1242 MW. Energiasalv is constructing 550 MW underground Pumped Storage Hydropower, but it would not cover the excess electricity produced by distribution grid. Thus, there is potential for demand side response or additional storage in the range of 700 MW [46]. However, it is important to note, as this study does not cover additional generation capacity in the transmission network, actual need for DSR or storage capacity might be even higher.

One of the main market issues related to demand side response potential is the number of consumers using fixed priced contracts. Consumers with fixed price contracts lack the incentive to provide demand response services. In Lithuania about 70% of business consumers use fixed price contracts. [44] If more consumers would use spot market price contracts, then they could take advantage of shifting their energy demand hours, which could in turn reduce the consumers' energy bill and reduce the need for additional generation at peak consumption hours.

Back-up generation is a possibility for demand response participation. According to the EA study using a back-up generator for demand response has a variable cost of 250-300 €/MWh, nonetheless the activation cost of a back- up generator would be 2500 €/MWh. [44] The grid connected battery storage solutions are discussed in Chapter 4.8.

Various countries have proposed different incentive schemes to increase the demand side response potential. For example, UK has proposed a compensation scheme to motivate households to shift their consumptions during peak load hours. If this compensation scheme is implemented the consumers could be compensated up to 7 €/kWh, the typical retail electricity price for home users (as of 2022) in the UK is approximately 0,33 €/kWh. [47]

In conclusion, as the share of renewable energy sources like solar power and wind power increases in the grid and the electrification of energy demand sectors, such as the transport sector, increases peak demand, it is very important to consider, encourage and develop DSR and storage capacity in the network.

4.2. "Typical" datacentre

As the use of the Internet and different cloud-based solutions is ever increasing, so is the building of new data centres. There already are data centres in Estonia, for example, the largest data centre in Estonia is a data centre by Greenergy Data Centers, which is 14 500 m^2 in size and it has a power demand of about 32 MW. In the future, larger and more power intensive data centres could be built. Therefore, it is important to consider the effects of possible new data centres.

Data centres usually run 24/7 and are remarkably energy intensive with typical power densities of 538 to 2153 W/m^2. The ICT sector consumes about 7% of global electricity and is projected to rise up to 13% by 2030. The cooling systems of a power centre could account for up to 40% of the energy demands of a data centre, thus the cooling system has the most impact on data centre energy efficiency. [17]

Energy demand and load characteristics of a “typical” datacentre are based on European Commission technical report “Trends in data centre energy consumption under the European Code of Conduct for Data Centre Energy Efficiency”. Characteristics of average data of reporting facilities which represent the “typical” data centre are listed in Table 4.2. The average power utilisation effectiveness metric (PUE) which indicates the ratio of total data centre input power to IT load power is 1,8. Over the years PUE has improved resulting in more efficient data centres. The average rated IT load per floor area is 750 W/m^2. [17]

Table 4.2. Typical Data Centre [17]

Parameter	**Value**	**Unit**
Total dataset	289	facilities
Total annual electricity consumption	3 735 735	MWh
Average DC floor area	2616	m^2
Average Rated IT load	1956	kW
Maximum load	2699	kW
Average annual electricity consumption	13 684	MWh
Average annual IT consumption	7871	MWh
Average PUE	1,80	
Average High Temp Set point	25	°C
Average Low Temp Set point	19.5	°C
Average High Relative Humidity Set point	59	%RH
Average Low Relative Humidity Set point	35	%RH
Average annual electricity consumption per floor area	5.23	MWh/m^2
Average rated IT load per floor area	0.75	kW/m^2

Figure 4.7 depicts the hourly electricity consumption for a data centre in Barcelona during summer and winter. The consumption increases during evening hours and is lower in general during the winter period [48]. Figure 4.8 depicts monthly data centre consumptions for different data centre locations. In general, the consumption patterns and amounts are similar in all locations, being slightly higher in Barcelona. The monthly energy consumption of data centres increases during summer months in all locations. Cloud computing and virtualization technologies enable data centres to dynamically migrate load to distributed data centres to respond to hourly variations to reduce energy consumption and the energy costs of data centres. [48]

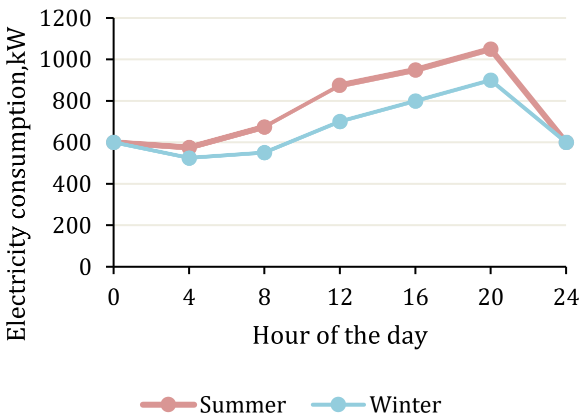


Figure 4.7. Hourly electricity consumption for a data centre in Barcelona [22]

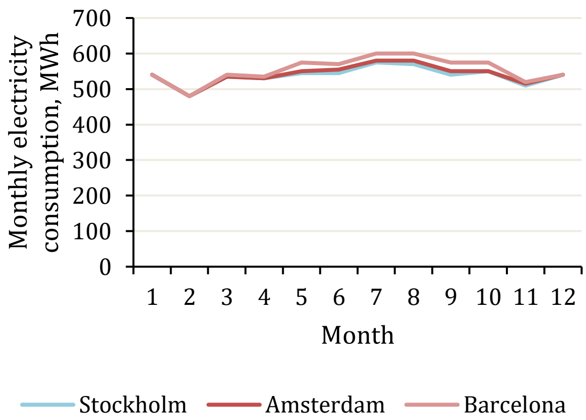


Figure 4.8. Monthly electricity consumption for the different locations [22]

As the demand for data centres is increasing, and it is likely for more and larger data centre to be built in Estonia, it is crucial to be ready for their building, as they use a large amount of power and need a solid electricity grid to support them.

4.3. District heating heat pumps

District heating is a proven technology to enable heating and domestic hot water in populous areas. It also enables the integration of renewable energy sources into the energy system. Supplying heat produced with heat pumps to them is a solution with great potential in rural areas, as available land for such purposes is plentiful. In addition, heat pumps can help increase air quality, as they can replace heat produced by combustion of biomass or fossil fuels.

Energy and peak load characteristics of district heating heat pumps that was used in the district heating model is seen on Figure 4.9. District heating heat pump demand profile is no different from the heating boiler. Electricity consumption is lessened by the coefficient of performance of the heat pump.

With base scenario assumptions, in the 2030 the peak demand of small district heating networks in Estonia that use electricity for heating would be 7,2 MW. Extreme climatic conditions would increase the peak by 1,43 times. It is estimated that in the 2030, electrified district heating networks would consume 9 GWh of electricity. By 2050, the peak demand and consumption based on compiled scenario is expected to grow by 10 times, 72 MW and 88 GWh respectively.

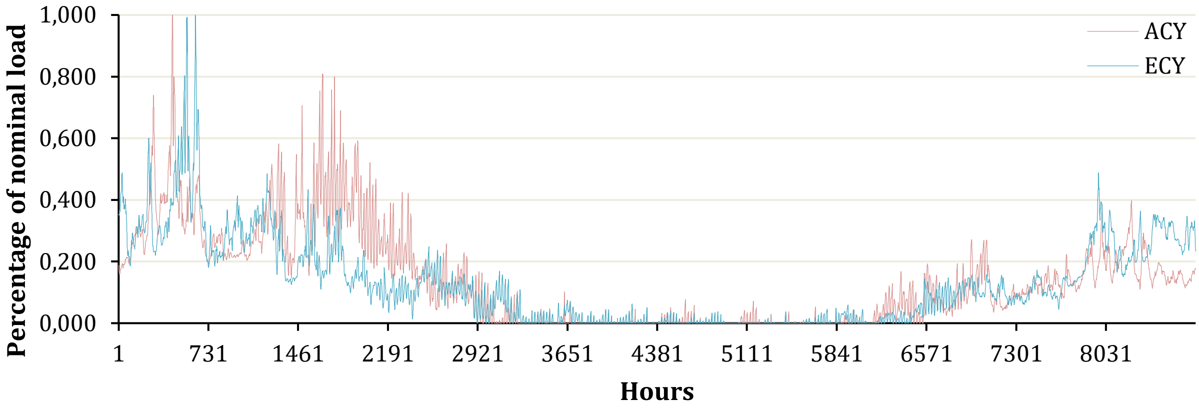


Figure 4.9. District Heating heat pump profile

In Figure 4.10 tests of over 1300 heat pumps are presented. The study was conducted by “The University of Applied Sciences Buchs”. **The study was made for heat pumps that are used in households not for industrial heat pumps**. In addition, large district heating networks can increase the efficiency of the heat pump by integrating heating and cooling or use water from rivers or sea as a heat source.

Figure 4.11 and Figure 4.12 show the temperature profile and heat pump efficiency with different air temperatures. If heat pump uses water as a source of heat, then the efficiency does not fall drastically during winter months as the source of heat would always be over 0 °C regardless of the air temperature. Smaller electrical district heating networks, which were analysed here, may not have such access, and usually work with air to water heat pump systems that are more affected by ambient air temperature [10].

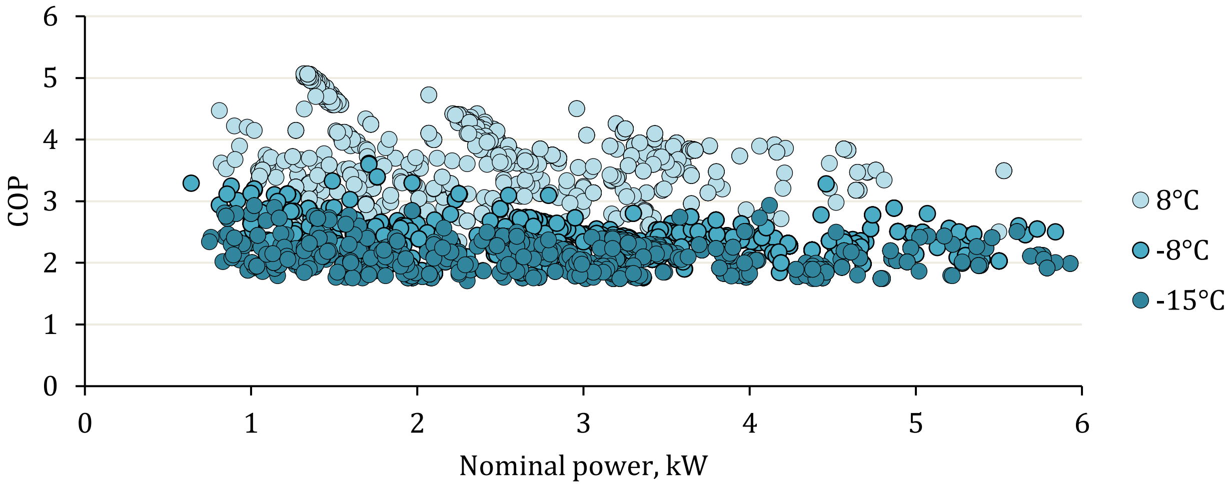


Figure 4.10. Heat pump ambient temperature and nominal power effect on COP

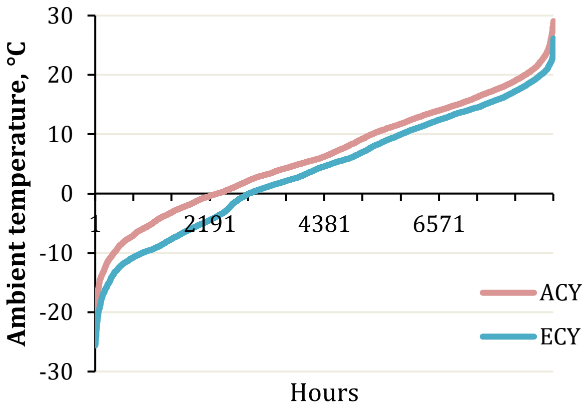


Figure 4.11. Ambient temperature profile

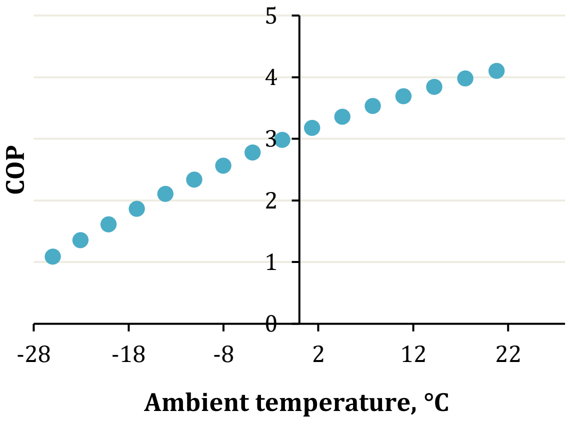


Figure 4.12. Heat pump efficiency (COP)

Results of average heat pump efficiency (COP) are provided in the following table (Table 4.3). Based on the values provided, a heat pump district heating system would have a COP around 3,0 if it is an air to water-based system and a bit higher COP if the heat from earth or water can be used as the efficiency would not fall as much during the wither months.

Table 4.3. Heat pump COP results

Ambient temperature	Miinimum COP	Average COP	Maximum COP
8 °C	2.1	3.7	5.1
-8 °C	1.8	2.4	3.6
-15 °C	1.7	2.1	2.9

For smaller district heating networks ground source heat pumps have the potential to be the most cost-effective solution when old boilers start needing to be replaced. From a consumer price point of view, using heat pumps to cover total demand could be the best solution.

4.4. District heating electric boiler combined with a heat storage

Electric boilers are devices to heat up water using electric power. Until today, district heating networks in Estonia have used only boilers powered by fossil or biofuels to generate heat. In the future, district heating networks could start using electric boilers as an additional source of heat supply to the system. Moreover, combining electric boilers with heat storage, they would be able to shift their demand to periods of time, where electricity is cheaper and leverage that to reduce the price of heat.

Large district heating electric boilers were found to be feasible if the electricity price falls below 30 €/MWh (Table 4.4). The calculation was based on the parameters of Tallinn district heating system and based on the data of year 2021. Grid costs were not considered as electricity would be directed into the boiler from the combined heat and power plant with a direct line.

Hours with electricity price under 30 €/MWh were looked up for further assessment. In 2021, there were 1086 hours where electricity was under the price point of 30 €/MWh. It would be appropriate to point out that during summer months there is usually no need for additional district heating and only long-term accumulation could be implemented – during the summer of 2021 (01.06.2021-31.08.2021) price fell below the 30 €/MWh point 69 times which makes up only 6% of the suitable price points for using an electric boiler for district heating. Power capacity of electric boiler cannot exceed that of a power plants electrical production as the investment would not be feasible using electricity from the grid with today's electricity prices. This could however change if enough renewable energy capacity would be installed, which could enable low grid electricity prices in time periods of high winds and high production of solar energy.

For comparison, electricity prices were lower in 2020, there were 4053 hours where electricity was under the price point of 30 €/MWh. In the summer of 2020 (01.06.2020-31.08.2020) price fell below the 30 €/MWh price point 780 times which makes up 19% of the suitable price points for using an electric boiler for district heating. In total, it would have been feasible for 37% of the operating time to use electricity to heat up water (same value for 2021 would have been 12%). In conclusion, district heating networks with combined heat and power plants are in advantage due to the possibility of using an electric boiler with a direct connection to power generation.

Medium district heating networks without power generation will break even during the night when grid costs are currently lower (assuming grid connection price is around 30 €/MWh during the night) then electricity price should be below 10 €/MWh. However, when analysing the current market, such prices are more likely to be around the times when heat consumption is low or non-existent. The smaller the district heating network, the less likely there is domestic hot water production during the summer. Thus, electric boiler has potential to work only during the heating period when the electricity price is high.

Table 4.4. Cost of an electric boiler with storage

District heating type	**Large**	**Medium**	**Small**
Annual heat consumption, GWh	**76**	**10**	**0.3**
CAPEX, €/MWh	10.9	19.9	29.0
OPEX, €/MWh	19.8	21.8	21.8
Total, €/MWh	**30.7**	**41.7**	**50.8**

In addition, to being another heat source for district heating providers, electric boilers with heat storage can also provide services to grid operators. One of these services is manual frequency restoration reserve (mFRR), which is a method of stabilizing the frequency of the electricity grid, an electric boiler is suitable for providing downward activations (consuming energy from the grid) as a service for manual frequency restoration reserve. This could be an affordable way for balancing the electricity grid in the future and a way to help stabilize electricity price on the market.

4.5. The building sector renovation program and energy performance

Estonia has a long-term strategy for building renovation, which sets out as a main goal to fully reconstruct all buildings, that were built before the year 2000, by the year 2050. The strategy sets out to reconstruct all buildings to energy class C by the year 2050, this means that in the next decades, 100 000 single-family dwellings, 14 000 apartment buildings and 27 000 non-residential buildings need to be reconstructed. An energy label with an energy class certifies compliance with the minimum energy performance requirements. An energy class indicates how much energy a building or part of a building consumes per square meter of heated area during one year or annum. The energy label with an energy class provides information on the planned energy requirements or the actual energy consumption of a planned or existing building. Energy consumption is the cost of heating, cooling, water heating, ventilation, lighting, electrical appliances, etc in a building.

The effect of renovation on direct building electricity use is insignificant if the building uses district heating. However, overall energy consumption shall drop, although lowering of consumption occurs in district heating stations, not in the direct electricity demand of a building. So, the costs for energy still become lower. Renovation affects mainly the use of heat and if heat is not produced from electricity, then the electricity consumption characteristics were assumed not to change. It was assumed that a renovated building would consume 38 kWh/(m²a) of electricity on appliances and ventilation with the rest being used for heating [15] [49].

The following example is created to bring out possible electricity use reduction of building renovation in apartments that use electricity (not district heating) for heating (Table 4.5) [49].

Table 4.5. Energy class weighted calculation

Energy class	**District heating, weighed values for comparison**	**District heating (actual)**	**Weighed electricity use (appliances)**	**Electricity available for heating**	**Required COP of heat pump**
Unit	**kWh/m²a**	**kWh/m²a**	**kWh/m²a**	**kWh/m²a**	**kWh/m²a**
A (weighed use up to 105 kWh/(m²a))	*29*	45	*76*	15	3,08
B (weighed use up to 125 kWh/(m²a))	*49*	75	*76*	25	3,08
C (weighed use up to 150 kWh/(m²a))	*74*	114	*76*	37	3,08
D (weighed use up to 180 kWh/(m²a))	*104*	160	*76*	52	3,08
E (weighed use up to 220 kWh/(m²a))	*144*	222	*76*	72	3,08
F (weighed use up to 280 kWh/(m²a))	*204*	314	*76*	102	3,08
G (weighed use up to 340 kWh/(m²a))	*264*	406	*76*	132	3,08
H (weighed use over 340 kWh/(m²a))	*324*	498	*76*	162	3,08

For a class A building the electricity available for heating would only be 15 kWh/m²a (considered weighing factor 2,0 for electricity; weighing factor is an evaluative factor that helps to evaluate the use of primary energy based on supplied energy to the building), but the building would need 45 kWh/m²a of heating. As without solar panels and/or a heat pump, energy class A cannot be achieved when using electrical heating, the calculation shows the maximum allowed electricity use for each energy class and does not analyse how the sufficient heating power could be achieved. A heat pump with COP of 3.08 or higher is required or solar panels which would need to produce 30 kWh/m²a for the building to use direct electrical heating and remain a class A building and have sufficient heating capacity.

Weighing factor of electricity is 2.0 and efficient district heating 0.65, if this assumption changes in the future, for example the weighing factor of electricity will be reduced, then the possible actual electricity use for heating can increase. The following table shows the potential of electricity consumption reduction per m² in buildings that use electricity for heating. Maximum electricity consumption reduction based on energy class is brought out in Table 4.6 [18].

Table 4.6. Electricity savings with apartment blocks with electric heating, kWh/m² [50]

Energy class	Heating (electricity), kWh/m²a	Appliances (electricity), kWh/m²a	TOTAL (electricity), kWh/m²a	Electricity savings after renovation to class A, kWh/m²a
A	15	38	53	0
B	25	38	63	10
C	37	38	75	23
D	52	38	90	38
E	72	38	110	58
F	102	38	140	88
G	132	38	170	118
H	162	38	200	148

There are 18 apartment buildings of 180 000 m² set to be renovated, but most of them use district heating which means that renovation would not have a significant impact on direct electricity usage. However, it will reduce the load on district heating and its energy usage. This helps to reach the goal of reducing reliance on fossil energy, enabling a shift towards more efficient and possibly electricity-based solutions. Total surface area of apartments that use electricity as primary source of heating is not precisely known so the consumption reduction potential was made for one m² per year for each energy class.

A class A building is required to have local renewable energy generation - usually solar energy. From 2020 all new buildings must achieve class A taking into account that without renewable energy generation the building must be of class B as to not compensate poor energy efficiency with renewable energy generation. Only the energy that is used by the building is counted in the reduction of energy consumption. The requirement for local energy generation does not apply if it is not economically viable due to shading from nearby tall objects or other reasons. The required and maximum solar panel capacities can be calculated for an average new building assuming the building's energy consumption without local renewable energy generation places it in the middle of class B (Table 4.7).

Table 4.7. Minimum and maximum PV parameters to reach class A

Building type	Single-family	Apartment	Other
Average net area a new building, m²	133	882	570
Average roof area of a new building, m²	129	348	545
Initial energy consumption, kWh/m²a	85	110	145
Final energy consumption, kWh/m²a	45	95	125
Necessary PV system size, kWp	7.8	16.9	14.5
Energy production per year, MWh	7.6	16.5	14.2
of which energy consumed, MWh	5.3	13.2	11.4
Maximum PV system size, kWp	13.1	44.2	69.2
Max. reduction in energy consumption, kWh/m²a	58	34	83

4.6. Home charging

There are two distinct possibilities for charging electric passenger vehicles: public charging and home charging. In countries, like Norway, where electric vehicles are much more common than in Estonia just yet, around 90% of all charging events take place at home. It is clear, that EV users prefer to charge their vehicles at home rather than at public chargers, as that is the most convenient way to do that.

Home charging of passenger vehicles is presented on the following graph (Figure 4.13). In the beginning of the considered time-series, the share of smart charging is relatively small. During the 2035-2040 period smart charging overtakes non-smart charging. In 2050, a large majority of home charging is of the smart type. Smart charging enables consumers to shift their demand to times where electricity price is lower, enabling consumers to save money while not suffering any real drawbacks. In addition, from the system operator's perspective, smart charging helps reduce peaks demand and facilitates the balancing of the network.

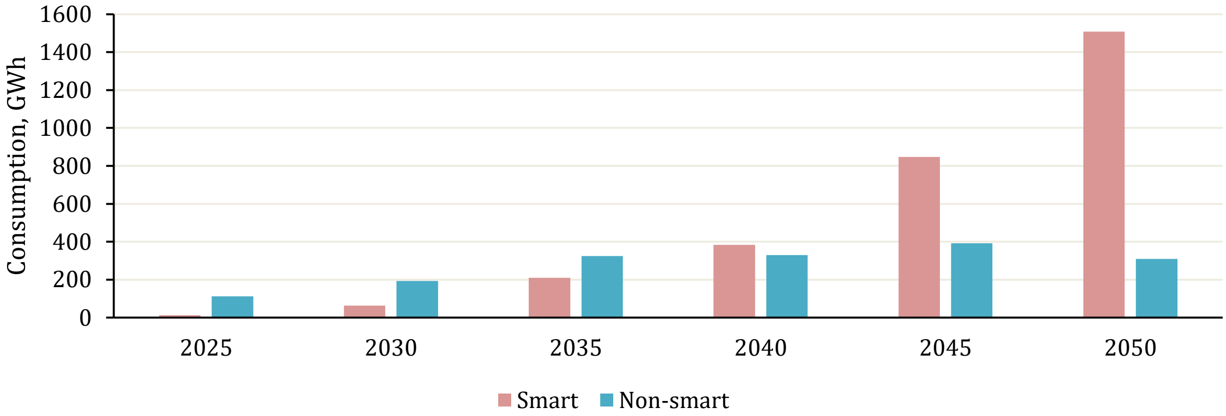


Figure 4.13. Home charging consumption

The uptake of vehicle to grid (V2G) in the future allows EVs to contribute power to the grid on suitable moments and with that reduce daily peaks of electricity consumption. Figure 4.14 - Figure 4.17 show that during winter V2G is beneficial for reducing peaks and shifting consumption to time-periods where consumption is lower. In summer, V2G can help store solar energy generated during the day and provide it to the network during evening peaks. The effect is projected to be relatively small until 2035, however this depends largely on the uptake of electric cars and people's interest in providing V2G services to the grid. Another important consideration is also people's habits on connecting their vehicles to chargers.

Participating in V2G could benefit consumers by providing an easy way to reduce their energy costs. This could happen in a couple of ways; it might be possible for consumers to participate in the day ahead market with their vehicles and charge their vehicles when electricity price is low and discharge them when it is high. They could also provide electricity grid balancing services to the grid operator. From the system operator's point of view, the need for additional flexible capacity is only growing, as it is predicted that solar power generation shall increase rapidly, which will likely reduce the price of electricity during the day by a large margin. If V2G price is low enough, then grid operators might be able to benefit from V2G instead relying on expensive peaking capacity that would only be used during the times when solar power generation is low.

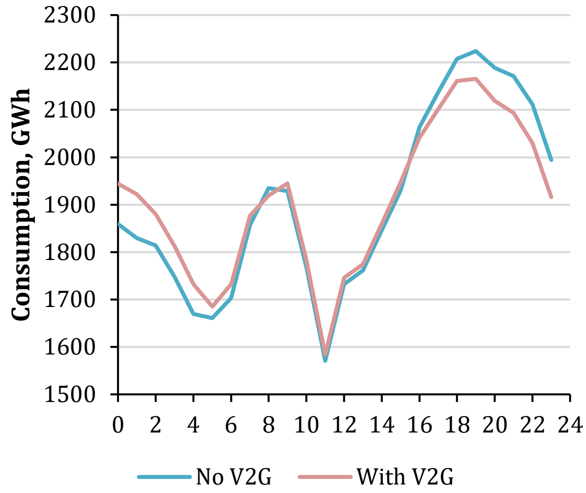


Figure 4.14. Example winter day 2045

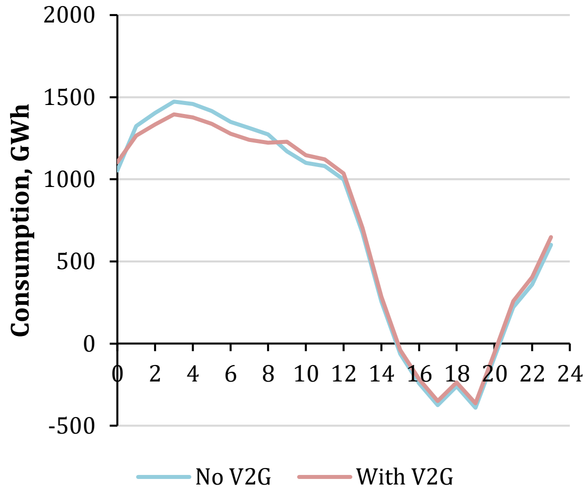


Figure 4.15. Example summer day 2045

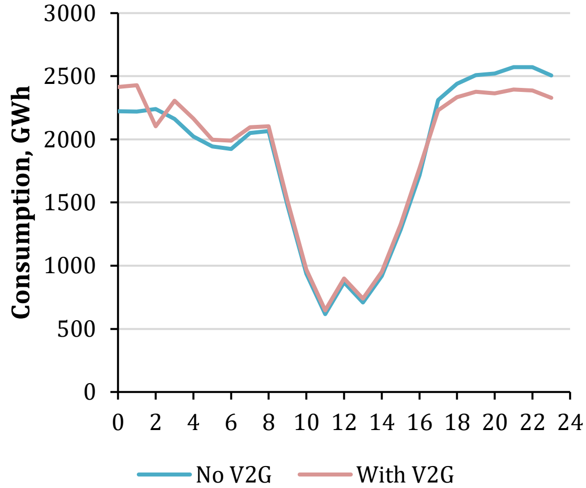


Figure 4.16. Example winter day 2050

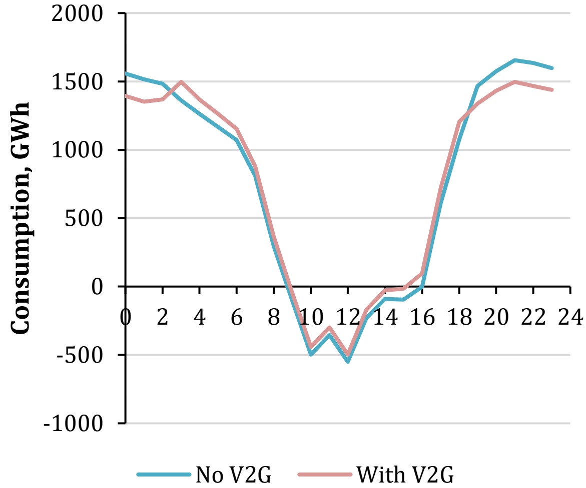


Figure 4.17. Example summer day 2050

V2G has great potential to be an excellent way for consumers to reduce their electricity costs, but also for system operators to have additional capacity for grid balancing purposes. V2G these days is still in an experimental state, and it is important to follow the developments on V2G and constantly evaluate possible uptake of it by consumers, because this way the actual capacity for demand response can be more accurately estimated.

4.7. Electric vehicle fleet

The effect of the addition of 100 electric busses; 1000 electric trucks and 10 000 electric passenger vehicles was analysed on the example of year 2030. Their average yearly distance travelled was taken into consideration. Table 4.8 describes the increase in yearly electricity consumption, and the increase of maximal and minimal hourly consumption values for each category. To estimate the effect of different types of electric vehicles on the grid, the charging profiles demonstrated on Figure 4.18 and Figure 4.19 were used. The first graph illustrates the different charging profiles of cars and vans, as multiple were used for different types of charging; the second graph describes the charging profiles used for buses and trucks. The charging profiles define what share of daily consumption is consumed by a group of vehicles with a particular vehicle type (cars and vans, buses, or trucks) with a particular charging type during an hour of a day, i.e., one daily profile adds up to 100% of the electricity.

A typical home charger could have a power of 11 kW. It must be noted that based on a Venegas et al study [1], analysis based on real EV driving and charging behaviour datasets have shown that EV users do not recharge their vehicles every day, even if they have easy access to a charger at their home. For example, the Electric Nation project in the UK demonstrated a median charging frequency of 3.64 times per week for all participants. In addition, as the average daily driving distance for cars is about 42 km/day (Table 4.8), so one car on average will consume only about 10 kWh of electricity per day. So, with an 11-kWh charger, this can be achieved within one hour. In conclusion, as in the real-world people charge their vehicles only 3-4 times per week and the required amount of electricity is not that large, it is extremely unlikely that most of EV users would regularly plug in their EVs every day at the same time and charge at the same time. Furthermore, wider prevalence of smart charging can help even further help distribute charging to take place over a longer part of the day as can be seen on the graph (Figure 4.18).

Table 4.8. Road transport sensitivity analysis

	Cars and vans	Buses	Trucks
Vehicles, pc	10 000	100	1 000
Average distance travelled, km/y	15 383	64 958	23 306
Yearly consumption, GWh	36.5	8.9	31.8
Peak demand, MW	10.1	2.2	9.6
Lowest demand, MW	1.1	0.3	0.4

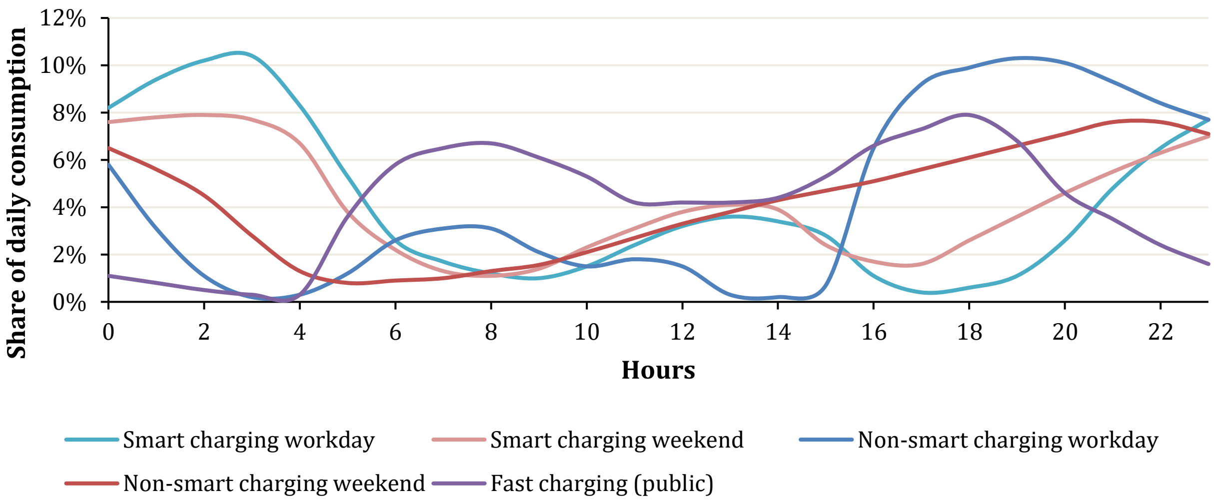


Figure 4.18. Cars and vans daily charging profiles

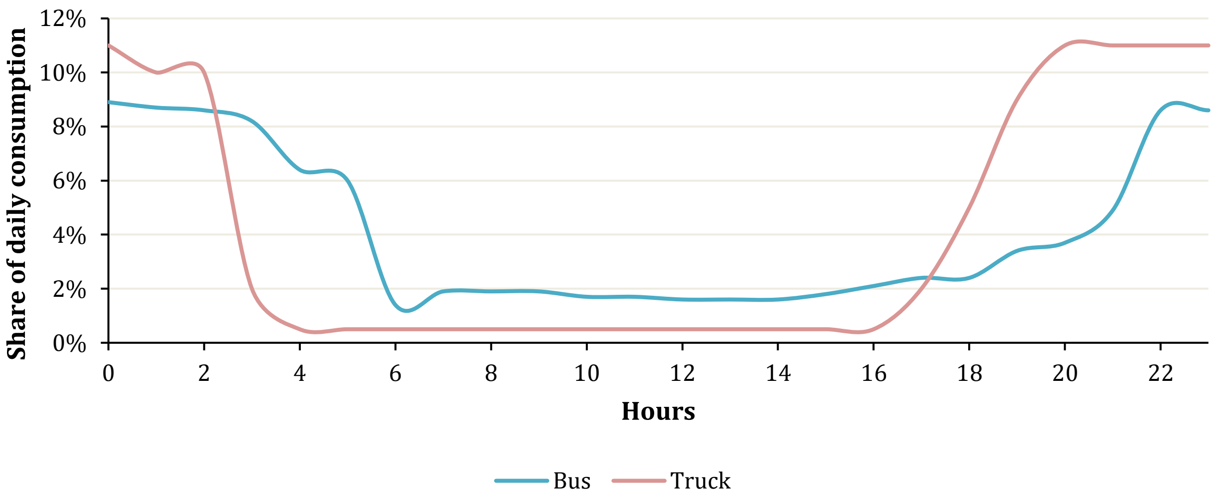


Figure 4.19. Buses and trucks daily charging profiles

The effect of an electric ferry on the electric grid was analysed based on the Virtsu - Kuivastu route This route was analysed, as there have been plans by the ferry operator to fully electrify at least one of their ferries, and it is a relatively short route which could easily be serviced by an electric ferry. It was assumed that the number of ferry trips per year stays on the same level as today and the schedule stays similar. Yearly electricity demand was estimated based on historical fuel consumption data. Diesel consumption was converted to electricity demand using efficiency coefficients of diesel and electric engines. Travel schedule was translated into hourly profiles, seasonality coefficients and weekly variation coefficients for generalizations to be made. Introduction of one ferry on these conditions would increase yearly electricity consumption by 6.5 GWh. Peak average hourly demand by such a ferry could be 1.25 MW, however actual charging power must probably be higher, as a Virtsu-Kuivastu ferry usually docks only for around 8 minutes. It would be possible for the ferry operator to use batteries or other storage devices in the port to reduce the effects of high-power on the grid (by charging a stationary battery while a ferry is not in the port)

Electric planes are in development phase and will probably be introduced for commercial use soon. As the battery energy density is not nearly sufficient for long haul flights, impact of short-haul flights was analysed. A 19 seat Heart Aerospace passenger plane was taken as an example. The plane would have a designed flight range of 400 km, charging power 1 MW and charging time of 40 minutes which would make the battery capacity around 667 kWh. A single airplane could make 5 short haul round trips during 24-hour period. Estimation was based on existing flight schedule, 4 round trips to Riga from Tallinn and 7 round trips to Helsinki from Tallinn (such a plane could also be used for example, on the Tallinn-Kuressaare-Tallinn flights). As international flights were considered, return flight charging was not included. Considering that the battery cannot be exhausted completely, charging time was estimated to be 30 minutes which would charge the batteries 500 kWh each cycle (1 MW charging power). A single small 19 seat electrical plane could therefore consume 2.5 MWh of electricity each day, with a peak load of 1 MW with an average charging time of 30 minutes.

An increase in road transport vehicles can have significant effects on the grid. As a comparison, 49 257 passenger cars were registered in Estonia during 2021 (of which 22 626 were new vehicles). As the interest in electric vehicles in the EU is growing, it is likely that in the coming years, 10 000 EVs (number of EVs of which the effects on the grid were analysed in this chapter) shall be introduced within only one year and demand then on will likely only grow. However, it is recommended to study the actual charging behaviour of Estonian EV users in the coming years, as only that will give insights into what the exact effects on the grid shall be, as it has been seen from other countries' experiences that people are not very consistent in plugging in their cars.

Since ferries are used only in a few areas of Estonia, their effect on the grid shall be quite localised to a specific location and substation and shall depend on the timetable of the specific ferry line. Relative effects on the entire grid shall not be very pronounced and so the electrification of each ferry must be analysed separately. The introduction of electric short haul planes is relatively feasible in the coming years, however as there are no concrete plans so far, an exact effect on the grid is difficult to estimate and shall depend heavily on the exact flight-plan. However, even for one small plane, 1 MW charging powers are expected (equivalent to about 90 EVs charging at the same time with a typical home charger).

4.8. Grid connected and market-based battery storage

Grid connected battery storage is an electricity storage method that uses batteries that are connected to the electricity grid as a way of storing excess electricity and providing additional power when needed. The system can work by operating in the Nord Pool day ahead market (utilizing daily price spread to make a profit) or work as a manual frequency restoration reserve (mFRR) for the grid operator. The system may be a part of a power generation unit with a direct line to reduce grid costs or as a separate unit in the grid.

In the following case, market-based battery storage means working every single day, based on Nord Pool day-ahead market prices, the battery charges during the hours with the lowest electricity price and discharges during highest prices. The system is assumed to be a sperate unit in the grid (not connected with a direct line). Lithium-ion battery was chosen as it is the most common type of battery for large-scale battery storage, it offers high energy density and cycle efficiency. Consumption, production, and price data of electricity was analysed for battery storage, data was extracted from a year-long period of 2021.04.19 - 2022.04.19 as an example of real conditions in the market. Assumptions for the cost of battery storage are shown in Table 4.9 [51] [52] [53].

Table 4.9. Assumptions for battery storage

Parameter	Value	Unit	Comment
Battery power	20	MW	Likely maximum storage power capacity to apply for a grant from KIK (Environmental Investment Centre)
Battery capacity	40	MWh	Most large-scale installed batteries have a duration between 0-4 hours (20 MW * 2 h = 40 MWh) [51]
Battery lifetime	3000	Cycles	Based on Lithium-ion battery average lifetime, after 3000 cycles, capacity drops below 80%
Grid costs and excise duties*	18	€/MWh	Based on the price list of Elektrilevi (operational costs) of medium voltage
Battery cost	100	€/kWh	Based on the cost of lithium-ion batteries [54]
Heat losses of storage and discharge	20	%	Lithium-ion batteries have relatively small losses during charging and discharging
Residual value of battery	30	%	Battery reaches 80% of capacity at the end of lifetime, can be used further as a second-hand battery [55]

**Renewable energy excise 11,3 €/MWh, transmission fee 8,8 €/MWh (day), 5,0 €/MWh (night), fixed capacity costs were not applied in €/MWh estimation*

A 40 MWh battery with a maximum power of 20 MW was estimated to cost around 4 000 000 € and expected to have a lifetime of 3000 charging cycles, then the battery capacity falls below 80%. 3000 cycles would sum up to 9,6 years. The model was constructed to be market-based: the battery would charge during the periods of lowest electricity price and discharge during the highest prices. The model ranks prices in a 24-hour period to determine whether to charge, discharge or to do nothing [51] [52].

The variation of the price of electricity was not wide enough to compensate the heat loss, grid costs, excises and the amortization of a grid connected battery. Using these assumptions, the amortization cost of the battery would be 292 600 €/y. The cash flow from the analysed period (2 148 231 €/y) would not be enough to overcome fixed grid costs (1 457 784 €), cost of storage (1 164 431 €) and cost of battery (292 600 €). Net profit also included fixed grid costs and sums up to -766 583 €. **The battery would not have been economically feasible under analysed conditions and operational behaviour even with high price fluctuations**. However, the second half of the period (which could represent a future scenario, where electricity price spread is larger, as with the introduction of more renewables into the system, electricity price is likely to have a larger price spread during a day) showed better results, but the spread was still large enough to make the system profitable. If only the second half of the analysed year is considered, the net profit would be -123 008 €.

Negative net profit in analysed conditions does not mean that a battery could not be profitable in market conditions but rather that the price fluctuations were too small, the battery was operated too often, or the cost of such a battery remains too high now. The cumulative cash flow from the second half of the year was 89% higher than the first part of the year, illustrating just how much can steep price fluctuations affect the feasibility of market-based batteries (and other storge solutions). The market-based battery may choose to be on the electricity market if a pre-set price spread, or profitability, is reached on the electricity market. Although direct cash flow, in the analysed scenario, would not be enough to justify a market-based battery system, the overall socioeconomic benefits may overweigh the financial aid required for the system to work as a battery system, may have a positive effect on average price of electricity for the consumers. With increasing power generation capacity of intermittent sources like solar and wind power, the price spread and spread regularity will likely increase. The cash flow from market-based battery and price fluctuations are shown in Figure 4.20.

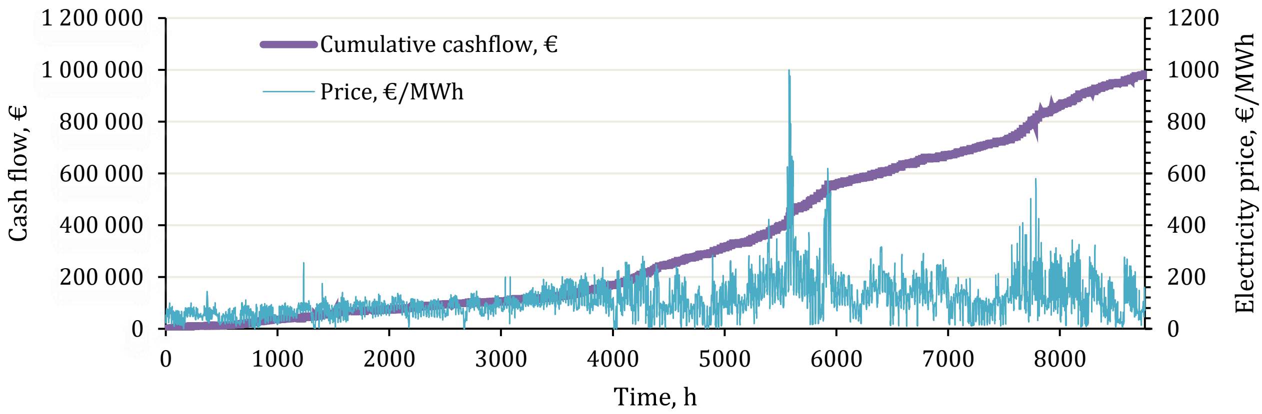


Figure 4.20. Price fluctuations and market-based battery cash flow

A 20 MW market-based battery would not have a significant effect in terms of decreasing peak demand and supply (Figure 4.21). On the other hand, a battery could offer more stable and cheaper average electricity prices, it is worth mentioning that a large-scale battery could have an impact on the price of electricity which in turn would decrease the profitability of a battery system as price fluctuations would be reduced - this factor was not considered in the analysis.

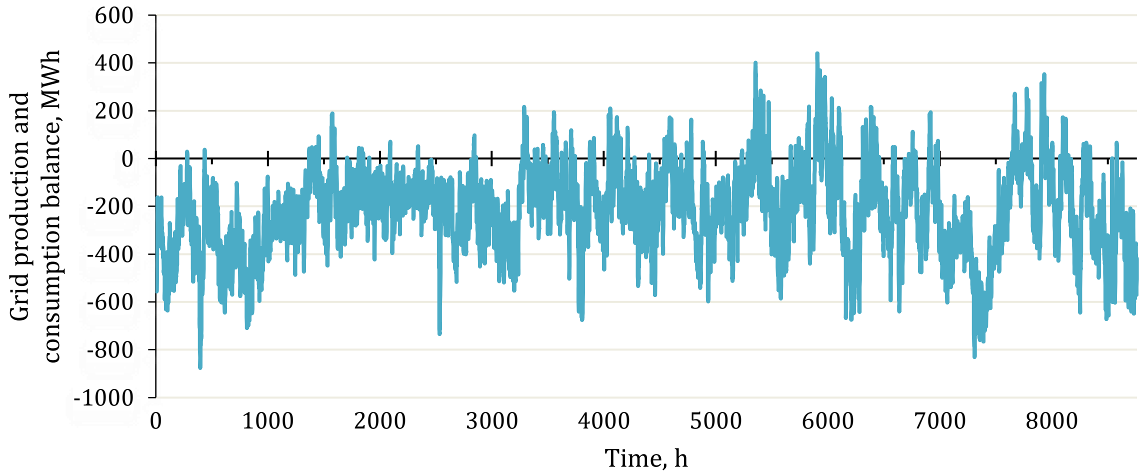


Figure 4.21. Grid balance with battery

Another way for the battery to operate would be in manual Frequency Restoration Reserve. mFRR must be, according to the guidelines proposed by the European Network of Transmission System Operators of TSO in Europe, fully deployable after 12.5 minutes and has a minimum duration period of 5 minutes. The battery would fulfil those requirements. Nearly 73% of large-scale battery storage power capacity provided frequency regulation in USA by 2019 data. [51] [52].

Also, in most countries there are two kinds of remuneration for the BSPs (Balancing Service Provider): one for keeping capacity available (capacity remuneration or capacity price) and one for actually activating capacity (balancing energy remuneration or energy price). The capacity remuneration is therefore a standby payment for the provision of capacity that in case of imbalances must be available within the set time frames of the mFRR reserve. The balancing energy remuneration or activation remuneration is the compensation for the actual delivery of the reserves. Currently in the Baltic States the BSPs are compensated only for their balancing energy, not their capacity. This will change however, when the new Balancing Services Market will be launched for the Baltic States synchronization with the European Frequency system.

The model showed that using battery as a part of mFRR energy bids would be much more feasible. The same assumptions as were in day-ahead market-based battery analysis, were considered in the model but the total capacity of the battery was reduced to 0,5 h (10 MWh), as there is no need for larger capacity in mFRR system. Cumulative cash flow from participating in mFRR would have been 438 659 €/y and the cost of battery 84 431 €/y. The battery had a longer lifetime in mFRR as there were less cycles in year. The battery could work both in the regular Nord Pool market and as a mFRR unit to maximise revenue. A market based (either for mFRR or Nord Pool day ahead market) battery would still not be feasible without additional remunerations. For a 20 MW 10 MWh battery to break even, 1 103 557 €/y should be covered for the BSP, in addition a profit margin should be included. Price point of maximum revenue for charging the battery was found to be 13 €/MWh (downward). The battery would not be feasible as the fixed grid costs would sum up to 1 457 784 €/y for a 20 MW battery. Revenue of mFRR battery is shown in Figure 4.22 for different scenarios (revenue from 100 – 400 €/MWh, cost of battery 1 000 000 € – 3 000 000 €).

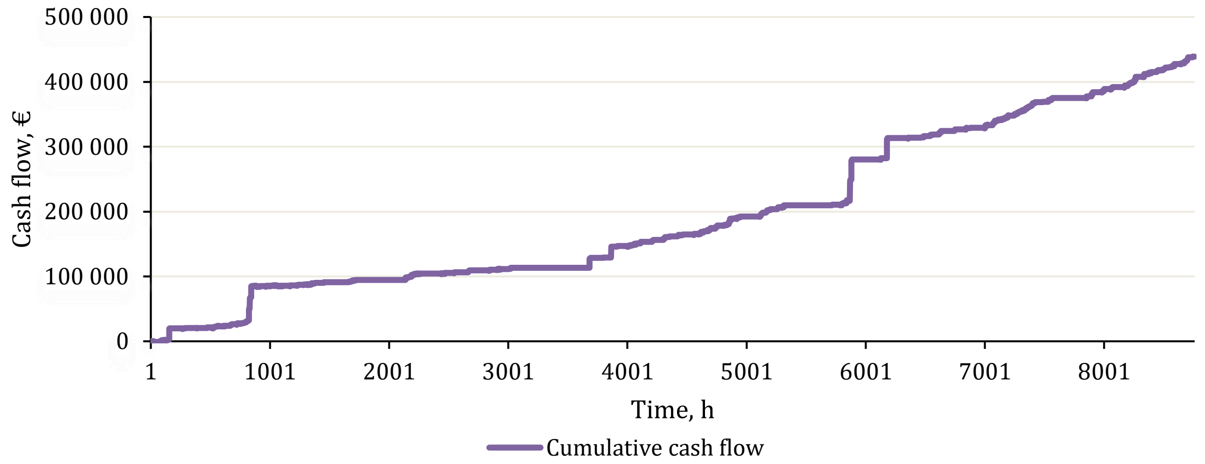


Figure 4.22. mFRR battery cash flow

To build a feasible battery system, either the cost of battery must fall, or the lifetime of battery systems must increase. If the daily price spread continues to increase, it is possible that batteries could be feasible without any additional income at all. Table 4.10 describes the profitability of an mFRR system using different assumptions. With lower battery costs and/or higher revenue from mFRR service, a battery system could be feasible.

Table 4.10. Impact of battery cost and average revenue from mFRR service (upwards and downwards) to net profit of battery system, €/year

Right, average mFRR revenue (up and down) Down, Cost of 20 MW 10 MWh battery	100 €/MWh	200 €/MWh	300 €/MWh	400 €/MWh
3 000 000, €	-1 267 814	-845 658	-423 501	-1 345
2 500 000, €	-1 215 044	-792 888	-370 732	51 424
2 000 000, €	-1 162 275	-740 118	-317 962	104 194
1 500 000, €	-1 109 505	-687 349	-265 193	156 963
1 000 000, €	-1 056 736	-634 579	-212 423	209 733

Even if the cost of battery would reduce significantly, the revenue from mFRR service must be higher than in the analysed period, for the battery to be feasible (Figure 4.23).

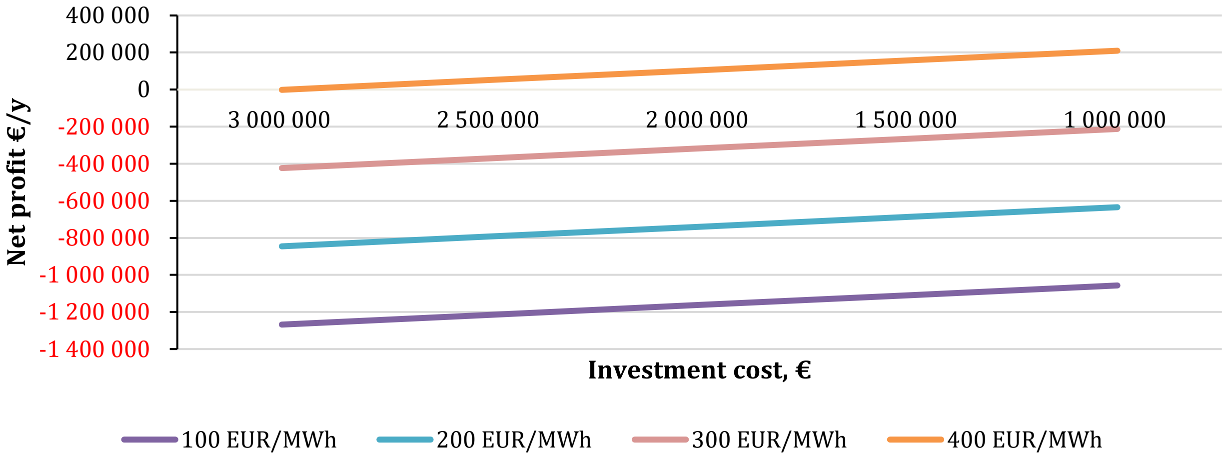


Figure 4.23 Feasibility of mFRR battery at different investment costs and revenues from mFRR service

4.9. Grid connected and market-based power-to-gas

Grid-connected and market-based power-to-gas is a method for converting surplus electrical energy available from the grid using electrolysis to chemical energy stored in the bonds of hydrogen gas molecules which can then be compressed, transported and used in industrial processes or released at a later date to transform the chemical energy back into electrical energy in fuel cells. In this way power-to-gas can provide load management similar to a battery, generating hydrogen with low electricity prices with the possibility to convert it back during periods of very high demand. Hydrogen has the additional benefit of the possibility of using the generated hydrogen in vehicles and industry. Using the produced gas to generate electricity should not be done through combustion and gas turbines however as the efficiency loss of converting the energy into heat energy and then to work is very high. The alternative is using a fuel cell system such as a solid oxide fuel cell (SOFC) which can work as an electrolyser, using electricity to generate hydrogen, or as a fuel cell converting chemical energy to electricity and heat. The heat can be used for district heating or industrial processes. Provided that enough hydrogen storage is available, power-to-gas is one of the most promising technologies for seasonal renewable energy storage.

The data for the power-to-gas analysis was taken from the IRENA green hydrogen cost reduction analysis. As there are multiple different applicable electrolyser technologies in use and development, the averages of the projected efficiencies and system costs were used up to 2050. The analysis is based on a 1 kgH_2/h model electrolyser which means the full load hours correspond to the quantity of the hydrogen produced [56]. Full load hours represent the annual utilisation of the electrolyser at design capacity.

The production price of hydrogen depends on two factors: the price of the electricity used for electrolysis and the cost of the system including the capital and operating expenditure. It would not be cost-efficient to run the electrolyser only when surplus electricity is available as the cost of the system would have to be offset and low to negative energy prices are rather uncommon today as not enough RES generation is available that would create these situations frequently enough. Even if in the future, low to negative energy prices become more common, the cost of the electrolyser system still has to be offset. Running the electrolyser on relatively high full load hours distributes the system cost to the produced hydrogen (Figure 4.24 - Figure 4.25). Even though the electricity used and its cost increase as the full load hours increase, a minimum hydrogen price appears around 5000 full load hours in 2020 and 2000 full load hours in 2050 with high electricity prices considering the decreasing CAPEX and OPEX of the system based on the IRENA green hydrogen cost reduction analysis [56]. This model used the electricity prices of 2021-2022 period with an average electricity price of 106.5 €/MWh as a high electricity price scenario. The price of the hydrogen generated can be read from the height of the blue and purple areas combined where the blue area is the combined cost of electricity to produce x kg of H_2 divided with the mass of the produced hydrogen whereas the blue area is the CAPEX + OPEX of the electrolyser divided with the mass of the produced hydrogen.

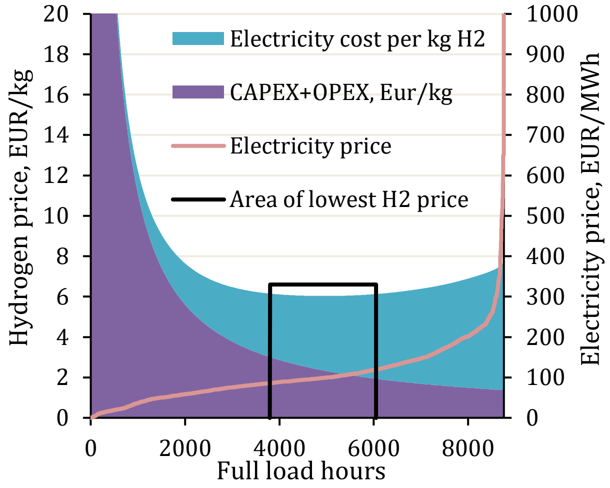


Figure 4.24. The price of hydrogen in 2020 with high electricity prices from 2021-2022

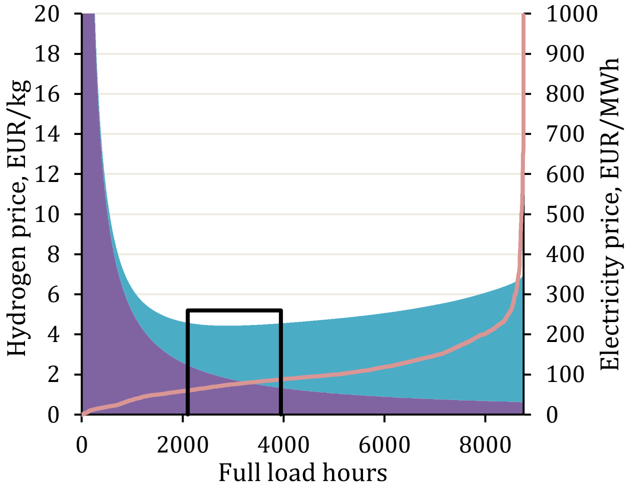


Figure 4.25. The price of hydrogen in 2050 with high electricity prices from 2021-2022

The price of the produced hydrogen is not only dependent on the average electricity price but also the shape of the load duration curve – therefore in practice high and low electricity price scenarios are used for more accurate illustration. The price of hydrogen will be lower if cheap electrical energy is available for most of the year even if very high peaks in electricity price are common. In the highly unlikely scenario that the price of electric energy is similar to the 2021-2022 period in the longer term, the price of hydrogen will fall from 6.03 €/kg in 2020 to 4.43 €/kg in 2050 due to the electrolysers becoming more efficient – 67% to 75% and the average capital expenditure falling from 884 to 419 €/kWe and operational expenditure from 18 to 8 €/kWe per year in the same timeframe (Table 4.11) [56]. The cut-off electricity price is the electricity price that corresponds to the lowest H_2 price visible on Figure 4.24 and Figure 4.25 though in reality, the electrolyser might be run for longer if the demand for hydrogen is high. The CAPEX + OPEX share is the contribution of the price of the electrolyser and its operation to the price of hydrogen. Similarly, the electricity share is the cost of the electricity that was used to generate the hydrogen at the lowest H_2 price point.

Table 4.11. The production price of hydrogen in 2020-2050 with high electricity prices

	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Lowest H_2 price, €/kg	6.03	5.60	5.10	4.95	4.79	4.62	4.43
Cut-off electricity price, €/MWh	99.11	92.30	84.38	81.95	79.35	76.57	73.60
Full load hours, h	4956	4355	3674	3478	3271	3085	2867
CAPEX+OPEX share, €/kg	2.33	2.18	2.03	1.98	1.93	1.87	1.82
Electricity share, €/kg	3.70	3.42	3.08	2.97	2.85	2.75	2.61

Taking the year 2020 as an example of a year with low electricity prices with an average of 33.71 €/MWh, the full load hours of the electrolyser are much higher and remain high along with the quantity of the generated hydrogen (Figure 4.26 and Figure 4.27). The lowest production price of hydrogen would fall from the 2020 value of 3.30 to 2.28 €/kg in 2050 (Table 4.12).

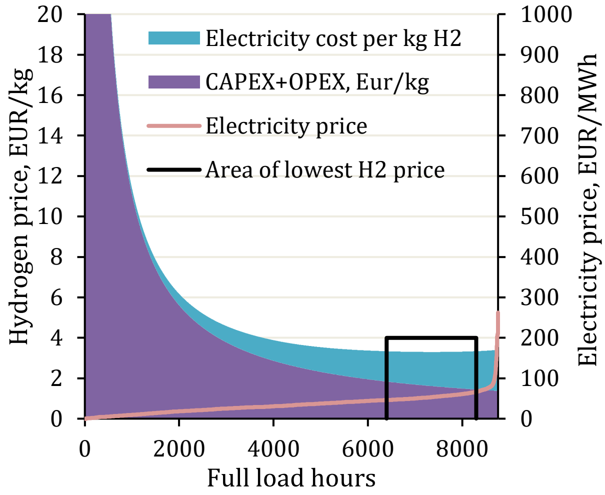


Figure 4.26. The price of hydrogen in 2020 with low electricity prices from 2020

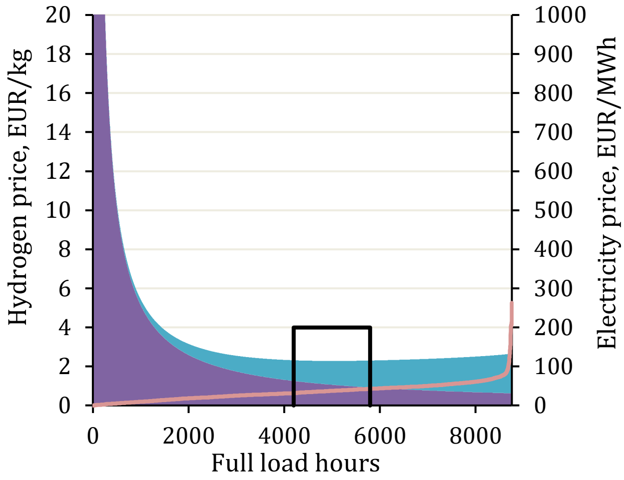


Figure 4.27. The price of hydrogen in 2050 with low electricity prices from 2020

Table 4.12. The production price of hydrogen in 2020-2050 with low electricity prices

	2020	2025	2030	2035	2040	2045	2050
Lowest H_2 price, €/kg	3.30	3.01	2.69	2.59	2.49	2.39	2.28
Cut-off electricity price, €/MWh	53.29	48.82	43.91	42.42	40.86	39.25	37.54
Full load hours, h	7354	6858	5994	5776	5497	5321	5033
CAPEX+OPEX share, €/kg	1.61	1.42	1.27	1.22	1.17	1.10	1.05
Electricity share, €/kg	1.69	1.59	1.42	1.38	1.32	1.28	1.23

With lower CAPEX values, the cost of the electrolyser system is distributed quicker over the produced hydrogen with more variability present in the price of H_2 at low full load hours (Figure 4.28). With high full load hours the price of the hydrogen converges around 3 €/kg. A different image can be seen when fixing CAPEX and varying the electricity price from 0 to 100 €/MWh (Figure 4.29) where high full load hours still lower the price of H_2 but a large difference on the final price appears based on the cumulative cost of electricity. In other words, as the working hours rise, the cost of the electrolyser impacts the price of hydrogen less while the cost of electricity takes prominence. Using a constant average electricity price in the analysis shows that it would be beneficial to run the electrolyser all the time at maximum power, which is not the case with a real-life load duration curve.

With renewable energy sources becoming more widespread, a fall in electricity prices and surplus electricity is expected. As demand for hydrogen will rise with hydrogen vehicles becoming more widespread, taking advantage of low energy prices with electrolysers is lucrative. Though this will not make sense if surplus energy is available only on occasional basis as the cost of the electrolyser still needs to be offset.

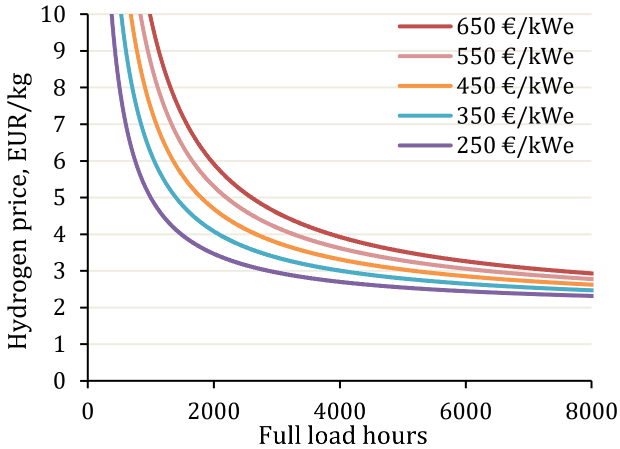


Figure 4.28. The price of H_2 with variable CAPEX and 40 €/MWh electricity price

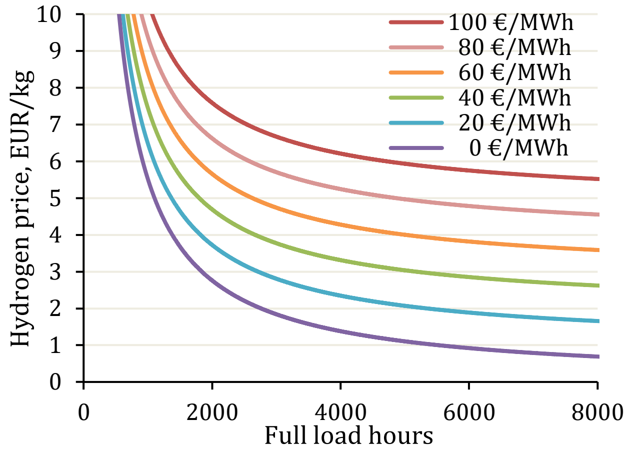


Figure 4.29. The price of H_2 with variable electricity price and 450 €/kWe CAPEX

5. References

[1] F. G. Venegas, M. Petit and Y. Perez, “Plug-in behavior of electric vehicles users: Insights from a large-scale,” *eTransportation,* no. 10, 2021.

[2] “European Commission website,” [Online]. Available: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en.

[3] “Council of the European Union website,” [Online]. Available: https://www.consilium.europa.eu/en/policies/green-deal/fit-for-55-the-eu-plan-for-a-green-transition/.

[4] Elering AS, “Elering LIVE,” 2022. [Online]. Available: https://dashboard.elering.ee/et. [Accessed 27 January 2021].

[5] Keskkonnaagentuur, “Ajaloolised ilmaandmed,” [Online]. Available: https://www.ilmateenistus.ee/. [Accessed 27 December 2021].

[6] Energiatalgud, “Elektri tarbimine,” [Online]. Available: https://energiatalgud.ee/Elektri_tarbimine. [Accessed 27 December 2021].

[7] Statistikaamet, “KE0240: Energiabilanss kütuse või energia liigi järgi,” 2021. [Online]. Available: https://andmebaas.stat.ee/Index.aspx?lang=et&DataSetCode=KE0240. [Accessed 27 December 2021].

[8] Ministry of Economic Affairs and Communications, “Estonia’s 2030 National Energy and Climate Plan,” 19 December 2019. [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/documents/ee_final_necp_main_en.pdf. [Accessed July 2022].

[9] K. Lepiksaar, K. Kalme, A. Siirde and A. Volkova, “Heat Pump Use in Rural District Heating Networks in Estonia,” *Environmental and Climate Technologies,* vol. 25, no. 1, pp. 786-802, 2021.

[10] Eastern Switzerland University of Applied Sciences, “Heat Pump Test Center WPZ Buchs,” 2022. [Online]. Available: https://www.ost.ch/en/research-and-consulting-services/technology/system-technology/ies-institute-for-energy-systems/heat-pump-test-center-wpz. [Accessed 18 04 2022].

[11] Keskkonnainvesteeringute Keskus, “Katlamajade ja torustike uuendamine, lokaalsed küttelahendused,” 2022. [Online]. Available: https://kik.ee/et/toetavad-tegevused/katlamajade-ja-torustike-uuendamine-lokaalsed-kuttelahendused. [Accessed 18 April 2022].

[12] Statistikaamet, “RVR02: RÄNNE HALDUSÜKSUSE VÕI ASUSTUSPIIRKONNA LIIGI, SOO JA RÄNDE LIIGI JÄRGI,” 2021. [Online]. Available: https://andmed.stat.ee/et/stat/rahvastik__rahvastikusundmused__ranne/RVR02. [Accessed 18 April 2022].

[13] International Transport Forum, “The Future of Passenger Mobility and Goods Transport in Estonia: Input Study for the Estonian Transport and Mobility Master Plan,” *International Transport Forum Policy Papers,* no. 78, 2020.

[14] Civitta, “Gaasitarbimise puhtale energiale ülemineku uuring,” Tallinn, 2021.

[15] Tallinna Tehnikaülikool, “Long-term strategy for building,” Tallinna Tehnikaülikool, Tallinn, 2020.

[16] Tarbijakaitse ja Tehnilise Järelevalve Amet, “Ehitisregister,” 2022. [Online]. Available: ehr.ee. [Accessed 18 April 2022].

[17] European Commission, “Trends in data centre energy consumption under the European Code of Conduct for Data Centre Energy Efficiency,” 2017.

[18] Riigi Teataja, “Hoone energiatõhususe miinimumnõuded,” 2020. [Online]. Available: https://www.riigiteataja.ee/akt/113122018014. [Accessed 18 April 2022].

[19] European Union, *Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings.*

[20] International Renewable Energy Agency, “Wind and Solar PV – what we need by 2050,” 1 January 2020. [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Webinars/07012020_INSIGHTS_webinar_Wind-and-Solar.pdf?la=en&hash=BC60764A90CC2C4D80B374C1D169A47FB59C3F9D. [Accessed 18 April 2021].

[21] NREL, “Research-Cell Efficiency Chart,” [Online]. Available: https://www.nrel.gov/pv/cell-efficiency.html.

[22] K. Bódis, I. Kougias, A. Jäger-Waldau, N. Taylor and S. Szabó, “A high-resolution geospatial assessment of the rooftop solar photovoltaic potential in the European Union,” *Renewable and Sustainable Energy Reviews,* vol. 114, no. 109309, 2019.

[23] EUROPEAN COMMISSION, “COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS,” 18 May 2022. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A221%3AFIN&qid=1653034500503#footnote9. [Accessed 25 May 2022].

[24] “EEA webpage,” [Online]. Available: https://www.eea.europa.eu/ims/new-registrations-of-electric-vehicles. [Accessed 19 07 2022].

[25] “European Parliament web site,” [Online]. Available: https://www.europarl.europa.eu/news/en/press-room/20220603IPR32129/fit-for-55-meps-back-objective-of-zero-emissions-for-cars-and-vans-in-2035. [Accessed 18 08 1993].

[26] L. Kaal, T. Metsvahi and A. Kendra, “Liiklusuuringu juhendi ja baasprognoosi koostamine,” Tallinna Tehnikaülikool, Tallinn, 2020.

[27] National Grid ESO, “Future Energy Scenarios,” 2020.

[28] F. M. Andersen, H. K. Jacobsen and A. P. Gunkel, “Hourly charging profiles for electric vehicles and their effect on the aggregated consumption profile in Denmark,” *International Journal of Electrical Power and Energy Systems,* no. 130, 2021.

[29] European Federation for Transport and Environment, “Comparison of hydrogen and battery electric trucks,” 2020.

[30] "Zero motorcycles web page," [Online]. Available: https://www.zeromotorcycles.com/fr-fr/model/zero-srs. [Accessed 03 06 2022].

[31] "Electric Nation webpage," [Online]. Available: https://electricnation.org.uk/resources/smart-charging-project/. [Accessed 03 June 2022].

[32] EY, "Rail Baltica Global Project Cost-Benefit Analysis," 2017.

[33] O. Piterina and A. Masharsky, "ENERGY CONSUMPTION OF RAIL BALTICA PROJECT: REGIONAL ASPECTS OF ENVIRONMENTAL IMPACT," *ECONOMICS AND CULTURE,* no. 16(1), 2019.

[34] Reaalprojekt, Hendrikson & Ko, Kelprojektas, Novarc, WSP, "Harju maakonnaplaneering Rail Baltic raudtee trassi koridori asukoha määramine," Tallinn-Tartu, 2013-2016.

[35] Reaalprojekt, Hendrikson & Ko, Novarc, Kelprojektas, WSP, "Pärnu maakonnaplaneering Rail Balticu raudtee trassi koridori asukoha määramine," 2016.

[36] Reaalprojekt, Hnedrikson & Ko, Novarc, Kelprojektas, WSP, "Rapla maakonnaplaneering Rapla maakonnaplaneering asukoha määramine," Rapla - Tartu, 2013 - 2016.

[37] Statistics Estonia, *Table KE0230,* Tallinn.

[38] Majandus- ja kommunikatsiooniministeerium, *Koondaruanne 2019. Raudteetransport,* Tallinn, 2019.

[39] "TS Laevad webpage," [Online]. Available: https://www.praamid.ee. [Accessed 03 06 2022].

[40] "NationalGridESO web page," [Online]. Available: https://www.nationalgrideso.com/. [Accessed 25 07 2022].

[41] "FuseBox web site," [Online]. Available: https://fusebox.energy/. [Accessed 25 07 2022].

[42] Konkurentsiamet, *Tarbimise juhtimine aitab elektrituru hindu alla tuua, kuid on hetkel suuresti kasutamata potentsiaal,* 2021.

[43] TalTech, Elering, *Tarbimise juhtimine Suurtarbijate koormusgraafikute salvestamine ning analüüs tarbimise juhtimise rakendamise võimaluste tuvastamiseks,* 2014.

[44] Ea Energy Analyses, *Summary Report & recommendations Lithuania demand response study,* 2018.

[45] Riigi Tugiteenuste Keskus, "Rohelisem Eesti," 23 March 2021. [Online]. Available: https://rtk.ee/rohelisem-eesti. [Accessed 18 April 2022].

[46] Energiasalv, "Energiasalv," 2022. [Online]. Available: https://energiasalv.ee/en/. [Accessed 01 06 2022].

[47] ERR, *Ühendkuningriik kavatseb elektri tarvitamata jätmise eest peale maksta,* 2022.

[48] E. O. J. S. Victor Depoorter, "The location as an energy efficiency and renewable energy supply measure for data centres in Europe," *Applied Energy,* 2015.

[49] Riigi Teataja, "Kaalutud energiaerikasutuse ja energiatõhususarvu klassi määramine," 12 August 2019. [Online]. Available: https://www.riigiteataja.ee/aktilisa/1070/7202/0013/Lisa_3.pdf#. [Accessed 12 August 2022].

[50] Riigi Teataja, "Hoone energiatõhususe arvutamise metoodika," 05 06 2015. [Online]. Available: https://www.riigiteataja.ee/akt/107072020012?leiaKehtiv. [Accessed 18 April 2022].

[51] U.S. Department of Energy, "Battery Storage in the United," U.S. Energy Information Administration, Washington, DC , 2021.

[52] U.S. Energy Information Administration, "Utility-scale battery storage costs decreased nearly 70% between 2015 and 2018," 23 October 2020. [Online]. Available: https://www.eia.gov/todayinenergy/detail.php?id=45596#. [Accessed 1 June 2022].

[53] D. GL, "2020 Battery Performance Scorecard," 2020.

[54] "Statista," Ströer SE & Co. KGaA, 2020. [Online]. Available: https://www.statista.com/statistics/883118/global-lithium-ion-battery-pack-costs/. [Accessed 2022].

[55] H. E. Melin, "The lithium-ion battery end-of-life market – A baseline study," 2018.

[56] International Renewable Energy Agency, "Green Hydrogen Cost Reduction," International Renewable Energy Agency, Abu Dhabi, 2020.

[57] International Energy Agency, "Net Zero by 2050. A Roadmap for the Global Energy Sector," International Energy Agency, 2021.

[58] European Commission, Directorate-General for Energy, "Comprehensive study of building energy renovation activities and the uptake of nearly zero-energy buildings in the EU," Publications Office, 2019.

[59] V. Depoorter, E. Oro and J. Salom, "The location as an energy efficiency and renewable energy supply measure for data centres in Europe," *Applied Energy,* vol. 140, pp. 338-349, 2015.

[60] European Union, *Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings.*

[61] Majandus- ja Kommunikatsiooniministeerium, "Eesti riiklik energia-ja kliimakava aastani 2030 (REKK 2030)," 2019. [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/documents/ee_final_necp_main_ee.pdf.

Annex 1. Electricity consumption profiles in the transport sector

Hourly electricity consumption profiles, %

Name\h		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Smart charging	Workday	8,2	9,4	10,2	10,4	8,3	5,3	2,6	1,7	1,2	1,0	1,5	2,4	3,2	3,6	3,4	2,8	1,1	0,4	0,6	1,1	2,6	4,8	6,5	7,7
Smart charging	Weekday	7,6	7,8	7,9	7,7	6,7	3,8	2,2	1,3	1,1	1,4	2,3	3,1	3,8	4,1	3,9	2,4	1,7	1,6	2,6	3,6	4,6	5,5	6,3	7,0
Non-smart charging	Workday	5,8	3,1	1,1	0,2	0,3	1,2	2,6	3,1	3,1	2,1	1,5	1,8	1,5	0,3	0,2	0,7	6,5	9,2	9,9	10,3	10,1	9,3	8,4	7,7
Non-smart charging	Weekday	6,5	5,6	4,5	2,8	1,3	0,8	0,9	1,0	1,3	1,6	2,1	2,7	3,3	3,8	4,3	4,7	5,1	5,6	6,1	6,6	7,1	7,6	7,6	7,1
Fast charging		1,1	0,8	0,5	0,3	0,3	3,6	5,8	6,5	6,7	6,1	5,3	4,2	4,2	4,2	4,4	5,3	6,6	7,3	7,9	6,8	4,6	3,5	2,4	1,6
Bus		8,9	8,7	8,6	8,2	6,4	6,0	1,4	1,9	1,9	1,9	1,7	1,7	1,6	1,6	1,6	1,8	2,1	2,4	2,4	3,4	3,7	4,9	8,6	8,6
Truck		11,0	10,0	10,0	2,0	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,5	2,0	5,0	9,0	11,0	11,0	11,0	11,0
Passenger train		0,6	0,5	0,4	1,0	2,0	4,8	6,3	6,0	5,3	4,8	4,6	4,8	4,9	5,1	6,3	7,0	7,4	7,6	7,3	5,8	4,0	2,0	0,8	0,7
Motorcycles		5,8	3,1	1,1	0,2	0,3	1,2	2,6	3,1	3,1	2,1	1,5	1,8	1,5	0,3	0,2	0,7	6,5	9,2	9,9	10,3	10,1	9,3	8,4	7,7
Freight train		4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2	4,2

Seasonality coefficients

Type\Month	1	2	3	4	5	6	7	8	9	10	11	12
smart	1,2856	1,2919	1,3319	0,9935	0,8432	0,8429	0,5482	0,9017	0,9149	0,909	1,0543	1,0829
dumb	1,2856	1,2919	1,3319	0,9935	0,8432	0,8429	0,5482	0,9017	0,9149	0,909	1,0543	1,0829
fast	0,8614	0,9129	0,9582	0,9078	0,8922	0,9999	1,3496	1,0719	0,9295	0,9953	1,0547	1,0666
moto	0	0	0	0	2,4	2,4	2,4	2,4	2,4	0	0	0

Average share of EVs plugged in

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Workday	44%	44%	44%	44%	44%	43%	38%	26%	17%	14%	13%	12%	12%	12%	12%	14%	17%	23%	28%	33%	36%	40%	42%	44%
Weekend	38%	39%	39%	39%	39%	38%	38%	36%	33%	28%	24%	22%	21%	21%	21%	23%	25%	27%	29%	31%	33%	35%	37%	38%

Average flexibility of EVs to provide V2G

Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Workday	57%	61%	44%	43%	42%	16%	23%	22%	29%	32%	33%	31%	31%	30%	33%	38%	41%	50%	52%	57%	61%	62%	61%	57%
Weekday	60%	59%	41%	45%	35%	31%	28%	25%	27%	26%	29%	33%	32%	37%	38%	45%	50%	51%	57%	59%	60%	63%	63%	58%

Ferry hourly consumption profiles

Name\h		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Virtsu - Kuivastu	Workday	4,8	4,8	0,0	0,0	0,0	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8	4,8
Virtsu - Kuivastu	Weekend	5,0	5,0	0,0	0,0	0,0	0,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0	5,0

Ferry seasonality coefficients

month		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Virtsu - Kuivastu		0,91	0,87	0,85	0,87	0,97	1,22	1,39	1,32	1,07	0,93	0,75	0,84

Ferry weekly variation

day		**1**	**2**	**3**	**4**	**5**	**6**	**7**
Virtsu - Kuivastu	Not summer	0,99	0,99	0,99	0,99	1,15	0,78	1,10
Virtsu - Kuivastu	Summer	1,03	1,03	1,03	1,03	1,03	0,88	0,96

Annex 2. BASE scenario results

Level 1

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 191	2 318	2 547	2 772	2 997	3 206
Commercial and public sector	GWh	3 398	3 570	3 975	4 312	4 583	4 798
Industry	GWh	2 602	2 635	2 657	2 806	3 008	3 306
Transport	GWh	281	586	1 095	1 469	2 366	3 269
Total consumption	**GWh**	**8 472**	**9 109**	**10 274**	**11 359**	**12 954**	**14 579**
Peak consumption	MW	1561	1649	1875	2080	2384	2713
Peak consumption (summer)	MW	992	1078	1201	1303	1473	1658
Lowest consumption	MW	527	592	687	782	927	1087

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 279	2 407	2 649	2 886	3 122	3 342
Commercial and public sector	GWh	3 543	3 720	4 125	4 458	4 720	4 926
Industry	GWh	2 708	2 740	2 760	2 921	3 134	3 447
Transport	GWh	281	585	1 092	1 463	2 356	3 253
Total consumption	**GWh**	**8 811**	**9 452**	**10 626**	**11 728**	**13 333**	**14 969**
Peak consumption	MW	1720	1813	2036	2229	2493	2802
Peak consumption (summer)	MW	1053	1135	1260	1381	1555	1732
Lowest consumption	MW	546	605	692	780	919	1075

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 263	2 391	2 632	2 866	3 101	3 320
Commercial and public sector	GWh	3 517	3 693	4 094	4 425	4 687	4 893
Industry	GWh	2 693	2 726	2 748	2 903	3 112	3 422
Transport	GWh	284	589	1 098	1 472	2 370	3 273
Total consumption	**GWh**	**8 757**	**9 399**	**10 572**	**11 666**	**13 270**	**14 908**
Peak consumption	MW	1724	1818	2041	2232	2494	2802
Peak consumption (summer)	MW	1009	1095	1223	1332	1505	1693
Lowest consumption	MW	527	592	687	782	927	1087

Level 2

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2130	2169	2271	2332	2372	2400
Commercial and public sector	GWh	3341	3426	3706	3884	3973	4004
Industry	GWh	2562	2534	2468	2505	2579	2748
Transport	GWh	281	587	1097	1474	2380	3306
Total consumption	**GWh**	**8314**	**8716**	**9542**	**10196**	**11304**	**12458**
Peak consumption	MW	1561	1648	1869	2060	2309	2712
Peak consumption (summer)	MW	985	1067	1185	1275	1437	1793
Lowest consumption	MW	527	459	300	80	-147	-383

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2219	2258	2373	2446	2497	2536
Commercial and public sector	GWh	3486	3577	3856	4030	4111	4132
Industry	GWh	2668	2639	2571	2620	2705	2888
Transport	GWh	281	585	1094	1469	2370	3291
Total consumption	**GWh**	**8653**	**9059**	**9894**	**10565**	**11683**	**12847**
Peak consumption	MW	1720	1813	2029	2210	2460	2955
Peak consumption (summer)	MW	1050	1127	1239	1341	1484	1824
Lowest consumption	MW	546	495	323	97	-142	-378

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2203	2242	2355	2426	2476	2513
Commercial and public sector	GWh	3460	3549	3826	3997	4077	4099
Industry	GWh	2653	2625	2559	2602	2683	2863
Transport	GWh	284	590	1101	1478	2384	3310
Total consumption	**GWh**	**8599**	**9006**	**9840**	**10504**	**11620**	**12786**
Peak consumption	MW	1724	1817	2035	2214	2462	2965
Peak consumption (summer)	MW	1005	1085	1199	1298	1445	1804
Lowest consumption	MW	527	464	301	74	-169	-404

Level 3

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	1968	1963	2018	2033	2027	2010
Commercial and public sector	GWh	3089	3108	3312	3420	3443	3418
Industry	GWh	2369	2297	2197	2195	2224	2339
Transport	GWh	281	587	1097	1474	2380	3306
Total consumption	**GWh**	**7708**	**7954**	**8624**	**9123**	**10074**	**11072**
Peak consumption	MW	1545	1632	1854	2043	2293	2697
Peak consumption (summer)	MW	971	1056	1174	1264	1408	1782
Lowest consumption	MW	200	-5	-272	-603	-949	-1299

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2056	2051	2120	2147	2152	2146
Commercial and public sector	GWh	3235	3258	3462	3566	3581	3546
Industry	GWh	2475	2402	2300	2310	2350	2479
Transport	GWh	281	585	1094	1469	2370	3291
Total consumption	**GWh**	**8047**	**8297**	**8976**	**9492**	**10453**	**11461**
Peak consumption	MW	1705	1797	2014	2195	2444	2940
Peak consumption (summer)	MW	1037	1111	1226	1336	1480	1797
Lowest consumption	MW	230	15	-256	-592	-946	-1294

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2040	2036	2102	2128	2131	2123
Commercial and public sector	GWh	3208	3231	3431	3533	3548	3513
Industry	GWh	2460	2388	2289	2292	2328	2454
Transport	GWh	284	590	1101	1478	2384	3310
Total consumption	**GWh**	**7993**	**8244**	**8923**	**9430**	**10390**	**11401**
Peak consumption	MW	1708	1801	2019	2198	2446	2951
Peak consumption (summer)	MW	991	1068	1191	1294	1441	1800
Lowest consumption	MW	195	-21	-291	-627	-970	-1306

Annex 3. HIGH scenario results

Level 1

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 204	2 364	2 657	2 912	3 117	3 300
Commercial and public sector	GWh	3 417	3 589	4 094	4 417	4 653	4 798
Industry	GWh	2 615	2 670	2 719	2 882	3 102	3 395
Transport	GWh	334	711	1 307	2 073	3 205	4 134
Total consumption	**GWh**	**8 569**	**9 334**	**10 777**	**12 283**	**14 077**	**15 626**
Peak consumption	MW	1590	1709	2018	2299	2672	3013
Peak consumption (summer)	MW	1005	1109	1252	1413	1623	1833
Lowest consumption	MW	531	605	712	834	1003	1138

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 292	2 456	2 771	3 044	3 265	3 467
Commercial and public sector	GWh	3 562	3 739	4 248	4 568	4 791	4 926
Industry	GWh	2 723	2 780	2 829	3 002	3 233	3 540
Transport	GWh	333	709	1 303	2 065	3 191	4 113
Total consumption	**GWh**	**8 910**	**9 684**	**11 151**	**12 679**	**14 480**	**16 046**
Peak consumption	MW	1752	1881	2188	2459	2781	3100
Peak consumption (summer)	MW	1067	1166	1316	1496	1708	1899
Lowest consumption	MW	552	619	713	829	993	1141

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 276	2 439	2 751	3 022	3 241	3 441
Commercial and public sector	GWh	3 536	3 712	4 215	4 533	4 756	4 893
Industry	GWh	2 706	2 762	2 812	2 981	3 210	3 514
Transport	GWh	336	714	1 311	2 077	3 209	4 138
Total consumption	**GWh**	**8 854**	**9 628**	**11 089**	**12 613**	**14 416**	**15 986**
Peak consumption	MW	1754	1884	2191	2459	2783	3114
Peak consumption (summer)	MW	1022	1127	1279	1445	1664	1849
Lowest consumption	MW	532	605	713	834	1003	1139

Level 2

Average Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2138	2204	2360	2438	2445	2432
Commercial and public sector	GWh	3359	3446	3826	3989	4043	4004
Industry	GWh	2575	2569	2530	2581	2673	2836
Transport	GWh	334	712	1310	2079	3222	4172
Total consumption	**GWh**	**8406**	**8930**	**10025**	**11087**	**12382**	**13443**
Peak consumption	MW	1590	1708	2012	2270	2631	3151
Peak consumption (summer)	MW	999	1098	1236	1378	1616	1962
Lowest consumption	MW	531	462	305	98	-130	-365

Extreme Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2231	2306	2494	2604	2640	2660
Commercial and public sector	GWh	3505	3596	3979	4140	4181	4132
Industry	GWh	2683	2679	2640	2702	2804	2981
Transport	GWh	333	710	1305	2070	3207	4151
Total consumption	**GWh**	**8752**	**9291**	**10419**	**11517**	**12833**	**13925**
Peak consumption	MW	1752	1880	2180	2431	2793	3328
Peak consumption (summer)	MW	1064	1158	1293	1451	1623	2006
Lowest consumption	MW	552	508	345	144	-82	-326

Extreme Climate Year 2

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2215	2290	2475	2582	2616	2634
Commercial and public sector	GWh	3479	3569	3947	4106	4146	4099
Industry	GWh	2666	2661	2623	2680	2781	2955
Transport	GWh	336	714	1313	2082	3225	4176
Total consumption	**GWh**	**8696**	**9235**	**10357**	**11450**	**12769**	**13865**
Peak consumption	MW	1754	1883	2183	2431	2795	3340
Peak consumption (summer)	MW	1019	1116	1253	1407	1634	1942
Lowest consumption	MW	532	474	322	117	-116	-356

Level 3

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	1959	1956	2041	2048	1984	1903
Commercial and public sector	GWh	3081	3068	3334	3395	3353	3230
Industry	GWh	2362	2287	2196	2185	2206	2285
Transport	GWh	334	712	1310	2079	3222	4172
Total consumption	**GWh**	**7735**	**8022**	**8881**	**9707**	**10765**	**11590**
Peak consumption	MW	1574	1691	1997	2253	2610	3134
Peak consumption (summer)	MW	983	1088	1226	1367	1605	1950
Lowest consumption	MW	157	-102	-425	-807	-1209	-1619

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2052	2059	2176	2213	2180	2131
Commercial and public sector	GWh	3227	3219	3487	3546	3491	3359
Industry	GWh	2470	2397	2307	2306	2337	2430
Transport	GWh	333	710	1305	2070	3207	4151
Total consumption	**GWh**	**8081**	**8384**	**9275**	**10136**	**11215**	**12071**
Peak consumption	MW	1736	1864	2164	2416	2778	3313
Peak consumption (summer)	MW	1049	1140	1282	1447	1617	2000
Lowest consumption	MW	190	-78	-394	-765	-1166	-1576

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2024	2014	2099	2105	2042	1966
Commercial and public sector	GWh	3194	3173	3424	3463	3393	3249
Industry	GWh	2389	2315	2217	2222	2233	2627
Transport	GWh	336	714	1313	2082	3225	4176
Total consumption	**GWh**	**7943**	**8216**	**9052**	**9872**	**10893**	**12018**
Peak consumption	MW	1713	1839	2133	2385	2746	3319
Peak consumption (summer)	MW	999	1091	1241	1397	1618	1927
Lowest consumption	MW	139	-145	-486	-887	-1314	-1733

Annex 4. LOW scenario results

Level 1

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 194	2 320	2 452	2 625	2 878	3 086
Commercial and public sector	GWh	3 420	3 635	3 869	4 168	4 476	4 731
Industry	GWh	2 617	2 669	2 708	2 822	2 996	3 210
Transport	GWh	188	373	614	789	1 176	1 543
Total consumption	**GWh**	**8 420**	**8 997**	**9 642**	**10 404**	**11 525**	**12 570**
Peak consumption	MW	1550	1638	1723	1863	2070	2239
Peak consumption (summer)	MW	976	1042	1117	1185	1290	1388
Lowest consumption	MW	524	582	651	721	821	925

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 282	2 407	2 537	2 713	2 980	3 191
Commercial and public sector	GWh	3 565	3 785	4 026	4 320	4 612	4 849
Industry	GWh	2 726	2 778	2 816	2 935	3 119	3 345
Transport	GWh	188	372	612	786	1 171	1 536
Total consumption	**GWh**	**8 762**	**9 343**	**9 990**	**10 755**	**11 882**	**12 922**
Peak consumption	MW	1711	1803	1907	2029	2212	2391
Peak consumption (summer)	MW	1037	1101	1177	1258	1368	1460
Lowest consumption	MW	540	595	662	731	824	920

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	2 266	2 391	2 522	2 698	2 962	3 172
Commercial and public sector	GWh	3 539	3 761	4 006	4 315	4 617	4 860
Industry	GWh	2 709	2 760	2 798	2 916	3 097	3 321
Transport	GWh	191	376	617	792	1 179	1 547
Total consumption	**GWh**	**8 705**	**9 288**	**9 943**	**10 721**	**11 856**	**12 900**
Peak consumption	MW	1714	1806	1910	2035	2218	2398
Peak consumption (summer)	MW	993	1061	1139	1215	1320	1432
Lowest consumption	MW	525	583	653	724	826	930

Level 2

Average Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2172	2261	2335	2427	2580	2682
Commercial and public sector	GWh	3402	3583	3759	3978	4186	4335
Industry	GWh	2605	2632	2631	2688	2793	2932
Transport	GWh	188	373	615	791	1181	1558
Total consumption	**GWh**	**8366**	**8849**	**9339**	**9884**	**10740**	**11507**
Peak consumption	MW	1550	1637	1721	1854	2043	2218
Peak consumption (summer)	MW	973	1036	1106	1168	1268	1458
Lowest consumption	MW	524	582	567	478	375	261

Extreme Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2260	2348	2420	2515	2682	2787
Commercial and public sector	GWh	3547	3733	3916	4131	4322	4454
Industry	GWh	2713	2741	2739	2802	2916	3067
Transport	GWh	188	372	613	788	1177	1551
Total consumption	**GWh**	**8708**	**9195**	**9687**	**10235**	**11097**	**11859**
Peak consumption	MW	1711	1802	1904	2022	2188	2333
Peak consumption (summer)	MW	1036	1098	1168	1238	1322	1516
Lowest consumption	MW	540	595	599	506	400	285

Extreme Climate Year 2

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2244	2332	2405	2499	2664	2769
Commercial and public sector	GWh	3521	3709	3897	4126	4328	4464
Industry	GWh	2696	2723	2721	2782	2894	3043
Transport	GWh	191	376	618	794	1185	1562
Total consumption	**GWh**	**8652**	**9140**	**9640**	**10201**	**11071**	**11837**
Peak consumption	MW	1714	1805	1908	2028	2194	2339
Peak consumption (summer)	MW	991	1057	1128	1192	1283	1442
Lowest consumption	MW	525	583	577	486	382	261

Level 3

Average Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2020	2080	2123	2185	2304	2376
Commercial and public sector	GWh	3166	3299	3426	3595	3758	3863
Industry	GWh	2424	2422	2393	2423	2499	2606
Transport	GWh	188	373	615	791	1181	1558
Total consumption	**GWh**	**7799**	**8174**	**8557**	**8994**	**9743**	**10403**
Peak consumption	MW	1534	1621	1704	1837	2027	2199
Peak consumption (summer)	MW	957	1019	1093	1157	1237	1446
Lowest consumption	MW	295	214	88	-74	-250	-442

Extreme Climate Year

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2108	2167	2208	2273	2407	2481
Commercial and public sector	GWh	3312	3450	3583	3748	3894	3982
Industry	GWh	2533	2531	2501	2537	2622	2741
Transport	GWh	188	372	613	788	1177	1551
Total consumption	**GWh**	**8141**	**8520**	**8905**	**9345**	**10100**	**10755**
Peak consumption	MW	1695	1787	1888	2006	2172	2317
Peak consumption (summer)	MW	1023	1083	1151	1219	1314	1494
Lowest consumption	MW	327	241	113	-55	-237	-431

Extreme Climate Year 2

Parameter	**unit**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Household	GWh	2084	2132	2162	2210	2317	2370
Commercial and public sector	GWh	3282	3414	3541	3697	3830	3905
Industry	GWh	2513	2509	2476	2501	2571	2669
Transport	GWh	191	376	618	794	1185	1562
Total consumption	**GWh**	**8070**	**8431**	**8796**	**9202**	**9903**	**10506**
Peak consumption	MW	1695	1784	1883	1998	2158	2297
Peak consumption (summer)	MW	978	1040	1107	1174	1262	1417
Lowest consumption	MW	287	193	54	-130	-333	-549

Annex 5. HIGH scenario results compared to BASE

Negative number means lower consumption.

Level 1

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	13	46	110	140	120	94
Commercial and public sector	GWh	19	19	120	105	70	0
Industry	GWh	13	35	62	75	94	88
Transport	GWh	52	125	212	604	839	865
Total consumption	**GWh**	97	225	504	924	1 123	1 047
Peak consumption	MW	29	60	144	220	288	299
Peak consumption (summer)	MW	13	31	51	110	150	174
Lowest consumption	MW	4	13	25	52	76	51

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	13	49	121	158	143	124
Commercial and public sector	GWh	19	19	123	110	70	0
Industry	GWh	15	40	70	81	99	93
Transport	GWh	52	124	211	602	835	860
Total consumption	**GWh**	99	232	525	951	1 147	1 078
Peak consumption	MW	31	68	152	230	289	298
Peak consumption (summer)	MW	13	32	56	115	152	167
Lowest consumption	MW	6	14	21	49	73	65

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	13	48	120	156	140	121
Commercial and public sector	GWh	19	19	121	108	69	0
Industry	GWh	13	36	64	78	98	92
Transport	GWh	52	125	212	604	839	865
Total consumption	**GWh**	97	229	517	947	1 146	1 078
Peak consumption	MW	30	66	149	226	289	311
Peak consumption (summer)	MW	13	31	56	114	158	156
Lowest consumption	MW	5	13	26	52	76	52

Level 2

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	8	34	89	106	72	32
Commercial and public sector	GWh	19	19	120	105	70	0
Industry	GWh	13	35	62	75	94	88
Transport	GWh	52	125	213	604	842	865
Total consumption	**GWh**	92	214	483	891	1 078	986
Peak consumption	MW	29	60	143	210	322	439
Peak consumption (summer)	MW	14	32	51	103	179	169
Lowest consumption	MW	4	3	5	18	17	19

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	13	49	121	158	143	124
Commercial and public sector	GWh	19	19	123	110	70	0
Industry	GWh	15	40	70	81	99	93
Transport	GWh	52	124	212	602	838	861
Total consumption	**GWh**	99	232	525	951	1 150	1 078
Peak consumption	MW	31	68	150	221	334	373
Peak consumption (summer)	MW	13	31	55	110	139	182
Lowest consumption	MW	6	13	22	47	61	52

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	13	48	120	156	140	121
Commercial and public sector	GWh	19	19	121	108	69	0
Industry	GWh	13	36	64	78	98	92
Transport	GWh	52	125	213	604	842	865
Total consumption	**GWh**	97	229	517	947	1 149	1 079
Peak consumption	MW	30	66	148	218	332	375
Peak consumption (summer)	MW	13	31	54	109	188	138
Lowest consumption	MW	5	10	22	43	53	48

Level 3

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	-9	-7	23	14	-43	-107
Commercial and public sector	GWh	-8	-40	22	-25	-91	-187
Industry	GWh	-7	-10	-1	-10	-18	-54
Transport	GWh	52	125	213	604	842	865
Total consumption	**GWh**	28	68	257	584	691	517
Peak consumption	MW	29	60	143	210	318	438
Peak consumption (summer)	MW	12	31	51	103	197	169
Lowest consumption	MW	-43	-97	-154	-203	-260	-320

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	-5	8	55	66	28	-15
Commercial and public sector	GWh	-8	-40	25	-20	-91	-187
Industry	GWh	-5	-5	6	-4	-13	-49
Transport	GWh	52	124	212	602	838	861
Total consumption	**GWh**	34	87	299	644	762	610
Peak consumption	MW	31	68	150	221	334	373
Peak consumption (summer)	MW	12	29	56	110	138	203
Lowest consumption	MW	-41	-92	-138	-173	-219	-282

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	-17	-21	-4	-23	-89	-157
Commercial and public sector	GWh	-15	-58	-7	-70	-155	-264
Industry	GWh	-71	-73	-72	-69	-95	173
Transport	GWh	52	125	213	604	842	865
Total consumption	**GWh**	-50	-28	130	442	503	618
Peak consumption	MW	6	38	114	187	299	368
Peak consumption (summer)	MW	7	23	50	103	177	127
Lowest consumption	MW	-56	-124	-195	-260	-344	-427

Annex 6. LOW scenario results compared to BASE

Negative number means lower consumption.

Level 1

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	3	2	-95	-147	-119	-121
Commercial and public sector	GWh	22	65	-106	-144	-107	-67
Industry	GWh	16	34	51	15	-12	-96
Transport	GWh	-93	-213	-481	-680	-1191	-1726
Total consumption	**GWh**	-52	-112	-632	-955	-1 429	-2 010
Peak consumption	MW	-11	-11	-151	-217	-314	-475
Peak consumption (summer)	MW	-16	-35	-83	-118	-183	-271
Lowest consumption	MW	-3	-10	-36	-61	-106	-162

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	3	0	-113	-173	-142	-152
Commercial and public sector	GWh	22	65	-99	-137	-109	-77
Industry	GWh	18	38	56	14	-15	-101
Transport	GWh	-93	-213	-480	-677	-1185	-1717
Total consumption	**GWh**	-50	-109	-636	-973	-1 451	-2 047
Peak consumption	MW	-9	-10	-129	-199	-281	-410
Peak consumption (summer)	MW	-16	-34	-83	-123	-188	-272
Lowest consumption	MW	-6	-10	-30	-49	-95	-155

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	3	0	-110	-169	-139	-148
Commercial and public sector	GWh	22	68	-88	-109	-70	-34
Industry	GWh	16	34	50	13	-15	-100
Transport	GWh	-93	-213	-481	-680	-1191	-1726
Total consumption	**GWh**	-52	-111	-629	-945	-1 414	-2 008
Peak consumption	MW	-10	-12	-131	-197	-276	-404
Peak consumption (summer)	MW	-16	-34	-85	-117	-186	-262
Lowest consumption	MW	-3	-9	-34	-57	-101	-157

Level 2

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	41	92	64	95	207	283
Commercial and public sector	GWh	61	157	53	94	214	331
Industry	GWh	43	98	163	183	214	184
Transport	GWh	-93	-214	-483	-684	-1198	-1748
Total consumption	**GWh**	53	133	-203	-313	-564	-950
Peak consumption	MW	-11	-11	-149	-206	-266	-494
Peak consumption (summer)	MW	-12	-31	-80	-107	-169	-335
Lowest consumption	MW	-3	122	267	398	522	644

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	41	90	46	68	184	252
Commercial and public sector	GWh	61	157	60	100	212	321
Industry	GWh	45	102	168	181	210	179
Transport	GWh	-93	-213	-481	-681	-1193	-1740
Total consumption	**GWh**	55	136	-207	-331	-586	-988
Peak consumption	MW	-9	-10	-125	-188	-272	-622
Peak consumption (summer)	MW	-14	-30	-71	-103	-163	-308
Lowest consumption	MW	-6	99	276	408	543	663

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	41	90	49	73	188	256
Commercial and public sector	GWh	61	159	71	128	251	364
Industry	GWh	43	98	162	180	211	180
Transport	GWh	-93	-214	-483	-684	-1198	-1748
Total consumption	**GWh**	53	134	-200	-303	-549	-948
Peak consumption	MW	-10	-12	-127	-186	-268	-626
Peak consumption (summer)	MW	-14	-28	-71	-106	-162	-362
Lowest consumption	MW	-3	119	276	412	551	666

Level 3

Average Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	52	117	105	152	277	366
Commercial and public sector	GWh	77	192	114	176	315	446
Industry	GWh	55	125	196	228	275	267
Transport	GWh	-93	-214	-483	-684	-1198	-1748
Total consumption	**GWh**	91	220	-67	-129	-331	-669
Peak consumption	MW	-11	-11	-150	-206	-266	-498
Peak consumption (summer)	MW	-14	-37	-81	-107	-170	-335
Lowest consumption	MW	95	219	360	529	699	857

Extreme Climate Year

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	52	115	88	125	255	335
Commercial and public sector	GWh	77	192	121	182	313	436
Industry	GWh	57	129	201	227	272	262
Transport	GWh	-93	-213	-481	-681	-1193	-1740
Total consumption	**GWh**	94	223	-71	-146	-354	-707
Peak consumption	MW	-9	-10	-126	-188	-272	-623
Peak consumption (summer)	MW	-14	-28	-75	-118	-166	-303
Lowest consumption	MW	97	226	369	537	709	863

Extreme Climate Year 2

Parameter	unit	2025	2030	2035	2040	2045	2050
Household	GWh	43	97	60	82	186	247
Commercial and public sector	GWh	74	183	109	164	282	391
Industry	GWh	53	121	187	210	243	215
Transport	GWh	-93	-214	-483	-684	-1198	-1748
Total consumption	**GWh**	77	187	-126	-228	-487	-894
Peak consumption	MW	-13	-17	-137	-200	-288	-654
Peak consumption (summer)	MW	-14	-28	-84	-120	-179	-382
Lowest consumption	MW	92	214	345	496	637	756