e-HIGHWAY 2050

Modular Development Plan of the Pan-European Transmission System 2050

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Start date	1st of September 2012	**Duration**	40 months
WP 2	**Developing the Grid architecture options as a function of the retained scenarios**		
D 2.1	**Data sets of scenarios for 2050**		

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Executive Summary

The project e-Highway 2050 aims at defining future transmission system structures that are capable of reaching the ambitious European climate targets. To cope with this task the project work has been split into several packages. In the first part of work package 1 (WP1) the following scenarios have been developed and selected and verbally described:

- **X-5: Large scale RES**: focus on the deployment of large-scale RES technologies. A high priority is given to centralised storage solutions accompanying large-scale RES deployment.

- **X-7: 100% RES electricity:** 100% based on renewable energy, with both large-scale and small-scale, links with North Africa. Thus, both large-scale storage technologies and small-scale storage technologies are needed to balance the variability in renewable generation.

- **X-10: High GDP growth and market-based energy policies**: Internal EU market, EU wide security of supply and coordinated use of interconnectors for cross-border flows and exchanges in EU. CCS technology is assumed mature.

- **X-13: Large fossil fuel deployment with CCS and nuclear electricity:** electrification of transport, heating and industry is considered to occur mainly at centralised (large scale) level. No flexibility is needed since variable generation from photovoltaic (PV) and wind is low.

- **X-16: Small and local:** The focus is on local solutions dealing with decentralised generation and storage and smart grid solutions mainly at distribution level.

These verbal descriptions build the basis for the scenario quantification to be performed. The objective of this process is to go from a European description of the scenario, mostly qualitatively, to a quantification of demand, storage, exchange and generation at the cluster level. The calculation and location of the demand and of the installed capacities for each generation technology over a geographical zone is a complex problem. Regarding the technical issues, the scenario development needs

- to consider a sufficient **spatial** level of details in order to take into account distributed phenomena such as the demand and the RES,
- to consider a sufficient **temporal** level of details in order to take into account intermittency renewable generation, and
- to ensure **adequacy** at any time (in fact at each hour).

Regarding the political issues, a methodology and a process are defined to ensure consistency between the national policies and the scenarios at European level.

As a first part of the work, demand in European countries for the different scenarios needs to be defined, based on the qualitative information that is given within the scenario descriptions. In this regard, several aspects to characterise the demand have been considered. At first, the demand development towards 2050 was depicted based on scenario socio-economic prognoses about gross domestic product (GDP) and population, which differ between the scenarios. After that, the effect of technological developments (e.g. electrification of heating and transport increases in efficiency) are used to adopt the yearly demand level. To get then to the final demand values grid, losses are approximated for each country (see: 2.1.3/ Annex A).

Based on the yearly values for demand and the targeted energy shares for each scenario, a first approximation of the installed capacities in the scenarios is made. Energy and capacity are linked by capacity factors that are used to assign a yearly energy amount to the different technologies. For thermal power plants, hydro power and biomass data from WP3 – technology assessment – are used, while the factors for wind and solar power, as most important renewable energy sources, are derived from weather data basis.

To implement an advanced approach of scenario quantification as planned in e-Highway 2050, not only the yearly energy values are considered, but also analyses of system adequacy at hourly time step resolution is followed throughout the whole scenario quantification process. In this regard, hourly demand time series are defined. Flexible demand is determined by implementing a demand-side management optimisation. The result shows that the controllability of parts of the energy consumption will be a very effective tool to system security of supply and decrease the need for power plants that provide system reserve (see: 3.1 and Annex D/E).

After these preparations a three step top-down approach is pursued to quantify the five e-Highway 2050 scenarios (see: chapter 4).

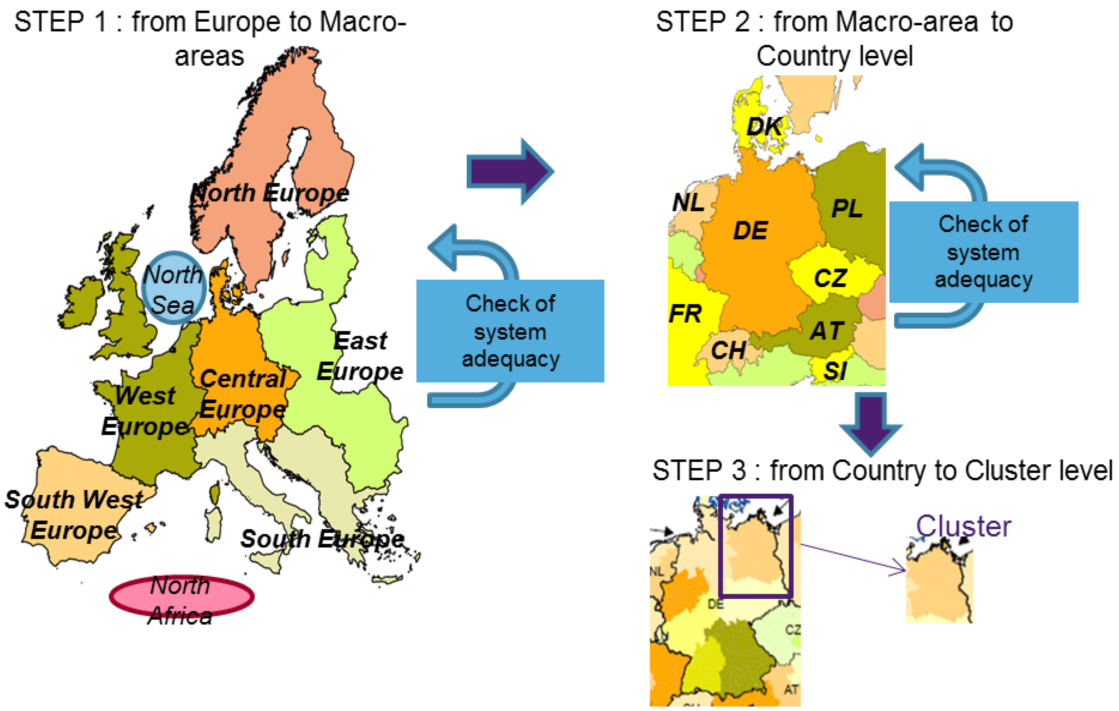

Figure 1: The three step top-down cluster approach

Step 1 starts with the computation of yearly demand values and energy targets per generation technology at European level. The installed capacities are defined in each macro-area based on weighting distribution keys which combine information about potential of generation capacities and demand in a given macro-area. The weights of the distribution keys are scenario dependent. For example, in the scenario X-5 (large scale RES), the weight for the wind potential is more important than for the demand. In the scenario X-16 (small and local), it is the opposite. Afterwards, a system simulation over whole Europe without considering internal grid constraints allows tuning the installed capacities and storage, in order to reach a sufficient level of adequacy and to improve the imbalances of the macro-areas according to the scenarios. In this step no country or national considerations were taken into account. Only the perspectives of the whole of Europe are considered.

In **step 2**, the priority is given to European perspectives. National policies and trends are considered while splitting the installed capacities of a macro area among its countries. The installed capacities of each macro-area are broken down to the country level, where thirty-three European countries are considered (ENTSO-E area). The distribution keys used to go from macro level to country level are the combination of information about potential of generation capacities, demand, policies and trends of each country. A particular attention is given to the National Renewable Energy Action Plan (NREAPs), providing the RES target European countries for 2020. These plans set the minimal values to be reached in each scenario for 2050. Then, as in the previous step, system simulations are performed for whole Europe, again without considering internal grid constraints, in order to provide the installed capacities and storage for a sufficient level of adequacy and to improve the imbalances of the countries according to the scenarios.

In the final **step 3,** the installed capacities of the different generation technologies are distributed across each country. Weighting distribution keys are also used which combine information about potential of generation capacities, demand and local constraints such as cities, mountains, natural areas.

The geographical clustering, that splits the European area into 106 clusters is the basis for the allocation of capacities. These clusters have been defined in such a manner, that they form the relevant incremental part for further analyses of system modelling in which the connection between them is reinforced.

The clusters are the same for all scenarios to enable cross-comparisons between scenarios.

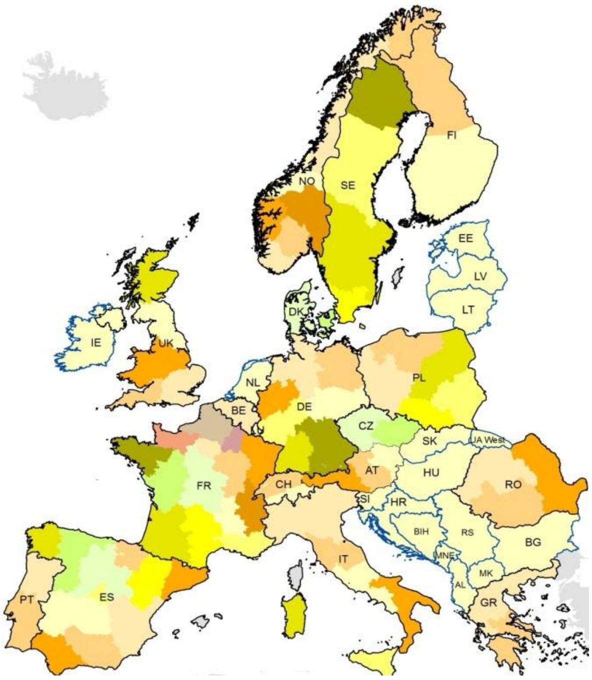

Figure 2: Geographical clustering

Throughout the application of the process a close interaction with the stakeholders, via ENTSO-e and the Electricity e-Highway Stakeholder Plattform, is sought. The study aims at defining overlay structures under extreme scenarios to depict possible developments towards the year 2050. The results are supposed to serve as orientation for national TSOs and help them to adjust their grid development planning. To increase the acceptance of results a consultation of results is launched to get remarks and opinions of a large variety Stakeholders. In the consultation Members of the EHSP (Electricity Highway Stakeholder Platform), TSOs via the ENTSO-e association are included and the feedback received has been implemented duly.
At the end of the process, the results have been consolidated after consultations of stakeholders, TSOs and other representatives through the Electricity e-Highway Stakeholders Platform.

Disclaimer

The five e-Highway 2050 scenarios are depicting contrasted, but possible developments of the energy system towards 2050. In all of these developments, an accomplishment of the European Climate target (80% to 95% reduction of CO_2-emissions compared to the level of 1990) is supposed to be reached. The project consortium does not consider one of these five scenarios to describe the real development, nor does it assumes one of these five scenarios to be more likely than the others. The approach aims at showing the development of the installed capacities, demand and the overlay structures under fundamentally different future circumstances. . The installed capacities of renewable energy sources that are identified in the analyses can be understood as "net-capacities", to be installed from now to 2050. Even if there are significant installed capacities of RES-technologies in some countries already today, the expected lifetime will have been exceeded in 2050. Thus all capacity that is indicated will have to be installed from now on to 2050.

Table of Content

List of Figures

List of Tables

1. Description of scheduled work in WP2 and selection of grid development approach

The project e-Highway 2050 develops energy scenarios and identifies the required electrical transmission grid needs in the year 2050. Once the target situation in 2050 is defined, a back-casting approach is used to suggest a possible pan-European modular development plan from the year 2020 to 2050. Within WP2, the energy scenarios verbally defined in WP1 are quantified: the load and generation capacities by technology are defined in detail (volume, localisation). This quantification process serves as a basis for system simulations on the starting grid (today's grid + decided reinforcements) and constraint analysis. New transmission corridors are identified and dimensioned which resolve these constraints and allow a secure grid operation. The identified transmission corridors are the incremental elements of the target overlay grid structures.

1.1. General approach and scientific challenges

The development of grid architectures is conventionally realised by adopting the "classical" methodological approach (see figure 3).

1.1.1. "Classical" approach

The "classical" approach for grid development consists of three tasks illustrated in the figure below.

Figure 3: Steps of the classical approach

Step1: Quantification of scenarios

In this first step, detailed scenarios of generation, demand and boundary conditions are identified and quantified not only at the national level but also down to each electrical node..

Step 2: Market simulations

With market simulations, the hourly in-feed of all generation resources aggregated by market place is calculated. This is classically done by minimising the overall generation cost while respecting all relevant constraints of the generation technologies and maximum exchanges between different market areas. This simulation serves as a data basis for more detailed and in-depth analysis of potential grid constraints. Country-internal grid constraints are not considered in this step.

Step 3: Grid development

The purpose of this step is to determine the potential bottlenecks in the system and the appropriate grid capacity reinforcements. The simulations are performed on a full description of the grid with power flow models. The proposed capacity reinforcements shall guarantee the supply of demand as well as the system stability and security in each hour, while respecting grid constraints.

However, this approach has limitations if applied **for a very long-term planning horizon**. Accuracy in the assumptions of load and generation at substation level is out of reach. This leads to the conclusion that the “classic” approach is not feasible for the elaboration of 2050 grid architectures for the e-Highway 2050 scenarios but that it requires methodological extension. A new approach should therefore be applied. This new approach introduces a simplified European grid model that allows forecasting generation and demand on a regional (“cluster”) level. It also develops the concept of system simulations and sanity check. An explanation of the two different approaches will be outlined in the following paragraphs.

1.1.2. Approach of e-Highway 2050

In comparison to the “classical” approach, the new approach applied by the e-Highway 2050 project consists of four instead of three steps (see figure 4). The step *quantification of scenarios* (now step 2) of the “classical” approach remains, but is slightly modified. The *grid development* part is now split into two parts: The *Grid Analyses* (step 4), which concentrates on contingency analyses and the actual *grid development*, which is now part of step 3. A new step 1 (*European Grid Model*) is added in the new approach and step 3 (*system simulations and grid development*) replaces the former *market simulations* of the “classical” approach in order to account for the long-term planning horizon. The following figure illustrates the new approach.

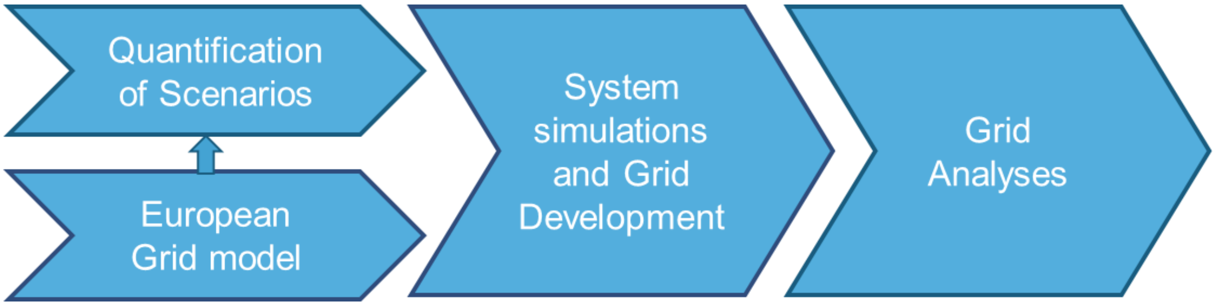

Figure 4: Steps of the approach of e-Highway 2050

Step 1: European grid model (Task 2.2)

The implementation of a simplified European grid model represents the most significant change of the "new" approach in comparison to the "classical" approach. The European grid model splits the pan-European transmission system into a number of interacting clusters that allow the development of possible overlay structures for 2050. The cluster model is based on a dedicated clustering algorithm where clusters are defined as aggregation of areas with similar characteristics. Load and generation of each cluster are then summarised in one virtual node. Inside one cluster a "copperplate" is assumed.

Based on a common model of the grid (Common Information Model developed by ENTSOE), an equivalent grid model is then developed to properly assess flows and their limits on this equivalent grid. More detailed information on the European grid model can be found in Deliverable 2.2 "European cluster Model of the pan-European transmission grid".

Step 2: Quantification of scenarios (Task 2.1)

The quantification of scenarios is also a challenging part and in some aspects also differs to the "classical" approach. Besides the very long term horizon, the set of data has to be allocated to the cluster model defined under the European grid model. This step is described within this Deliverable.

Step 3: System simulations and grid development (Task 2.3)

System simulations are carried out with a market simulator that takes into account the grid. The market simulator is used in a probabilistic way (for LOAD, Renewable Energy Sources, availability of thermal units, etc.) and analyses the adequacy and costs of the system. The grid is described in terms of a limited capacity of transmission between clusters. Parameters are set to take into account the repartition of the flows due to the impedances of the real transmission lines.

This step aims at performing system simulations, detecting grid constraints and then proposing reinforcement to solve these constraints.

More detailed information on system simulations will be given in Deliverable 2.3 "System simulation analysis and overlay-grid development".

Step 4: Grid analyses (Task 2.4)

The proposed grid architectures from step 3 have to be checked for their behaviour in the overall system. Therefore, the "classical" approach is further extended by the performance of sanity checks. For each scenario, a set of candidate architectures is provided and use cases are defined for detailed grid analysis. The sanity checks verify so that the use cases and the proposed overlay grid architectures can be operated using a full (alternating current (AC) load flow calculation model. This is especially relevant for highly loaded, long AC connections, along which the voltage level might drop under the tolerance level. The focus of this analysis is limited to a few, yet relevant, use cases.

Task 2.4 will check the suggested reinforcements for their ability to be operated in the existing system by performing fundamental grid analyses, such as N-1 contingency analyses.

More detailed information on system simulations can be found in Deliverable 2.4 "Contingency Analyses of Grid Architectures and Corrective Measurements".

1.2. Workflow in WP 2

The approach explained leads to the workflow of WP2 as shown in figure 5.

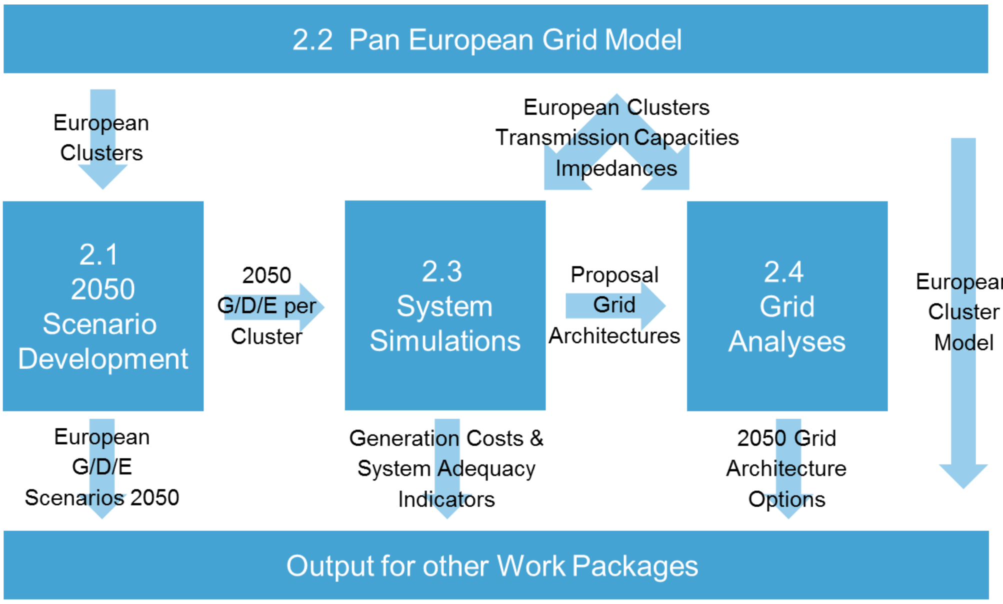

Figure 5: Work structure in WP 2

WP2 receives inputs from WP1 within the general assumptions, the boundary conditions and the verbal description of each scenario. WP3 provides technology performance and costs. For each 2050 scenario, WP2 proposes a set of candidate solutions for grid capacity enhancement for 2050 in order to limit congestions over an entire year.

2. Quantification of the e-Highway 2050 energy scenarios

In e-Highway 2050 the energy scenarios are a crucial part of the study, which have the highest effects on the results. Therefore a high acceptance is required, since there will only be understanding of the outcomes of the study when the quantification approach is comprehensible and all aspects and feedback has been considered.

2.1. Approach for the scenario quantification methodology

2.1.1. Purpose of the methodology

The purpose of the methodology is to define the installed capacities of each generation technology at cluster level while meeting the targeted energy mix as well as respecting the rationale of the 5 e-Highway 2050 scenarios and system adequacy (see Table 1). This is a highly complex problem due to:

- its size and uncertainties caused by the long term horizon;
- the need to consider a sufficient level of details in order to take into account distributed phenomena (renewable generation) requiring an hourly basis analysis;[1]
- the need to ensure consistency between national and EU policies;
- and the need to ensure adequacy at each hour.

Table 1: Verbal description of the 5 e-Highway 2050 scenarios

- **X-5: Large scale RES**: focus on the deployment of large-scale RES technologies. A high priority is given to centralised storage solutions accompanying large-scale RES deployment.

[1] There is a general trade-off between the need to be very accurate in spatial resolution (accuracy in grid analyses) and the possibility to forecast the futures generation allocation (precise position of renewable energy)

- **X-7: 100% RES electricity:** 100% based on renewable energy, with both large-scale and small-scale, links with North Africa. Thus, both large-scale storage technologies and small-scale storage technologies are needed to balance the variability in renewable generation.

- **X-10: High GDP growth and market-based energy policies**: Internal EU market, EU wide security of supply and coordinated use of interconnectors for cross-border flows and exchanges in EU. CCS technology is assumed mature.

- **X-13: Large fossil fuel deployment with CCS and nuclear electricity:** electrification of transport, heating and industry is considered to occur mainly at centralised (large scale) level. No flexibility is needed since variable generation from photovoltaic (PV) and wind is low.

- **X-16: Small and local:** The focus is on local solutions dealing with decentralised generation and storage and smart grid solutions mainly at distribution level.

2.1.2. Introduction and background

Starting from the description of the 5 scenarios provided by WP1, the quantification methodology aims to define the installed capacities of each generation technology at cluster level, while meeting the targeted energy mix of the scenario and the system adequacy in copper plate (generation satisfies the demand without grid constraints at all time).

The methodology is broken down into 3 different steps: installed capacities are first distributed at macro area level, then at country level and finally at cluster level. Thus, the spatial complexity increases with the level of precision in the quantification.

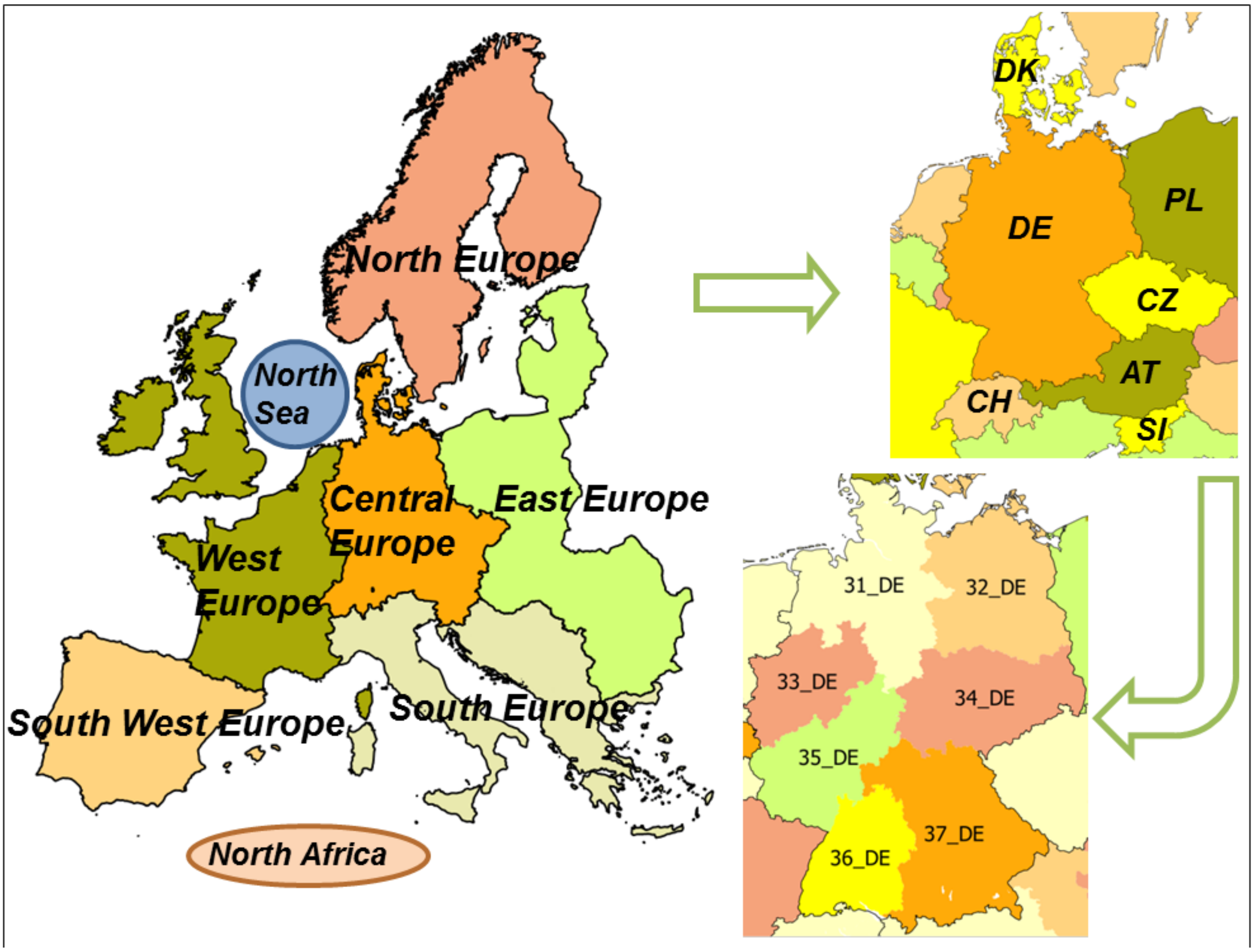

Figure 6: Schematic figure of scenario quantification approach

Three steps: macro area level, country level, cluster level

From the beginning of the calculations (macro area level and later country level), hourly simulations are considered. Thus, analyses are done in Power and not only in Energy. The approach can be described in the following processes:

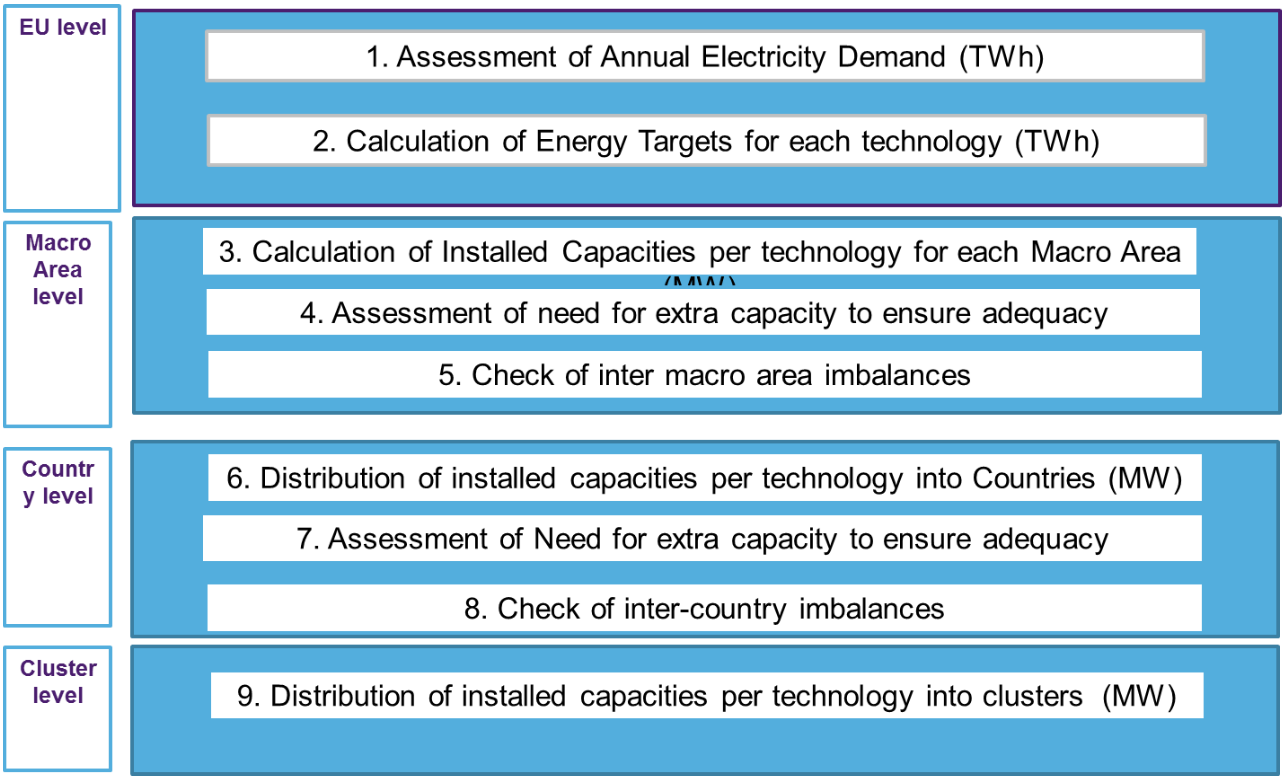

Figure 7: Methodological steps of scenario quantification approach

2.1.3. 1. Assessment of the annual electricity demand

Based on the information and assumptions about the evolution of the population, the GDP, the transfer of uses towards electricity and efforts on energy efficiency, a yearly volume of demand has been calculated for each country and for each scenario.

2.1.4. 2. Calculation of energy targets for each technology

For each scenario, a European energy mix (share of each generation technology in the annual generation) has been defined according to the description of the scenario from D2.1. From these shares and the annual European demand, annual generation targets per technology are defined.

2.1.5. 3. Calculation of installed capacities per technology for each macro area

Required installed capacities are computed from energy targets thanks to capacity factors. For wind, PV and CSP, capacity factors are defined for each area using time series built from meteorological data. For dispatchable plants (biomass, nuclear, fossil), a use rate of 80% is assumed in the first step, before hourly simulations.

For each type of generation technology, the European required installed capacity is distributed between the different macro areas thanks to “distribution keys”. These distribution keys are scenario and technology dependant and they are computed from the demand and the generation potential of the areas (see part three for more details on their calculations for each technology). In addition, potentials per area and per technology have been defined (see part three for more details) and are used as an upper bound for the installed capacities of each area (note : potentials are not scenario dependant).

The downscaling from European to macro area level is illustrated in the following diagrams for wind generation:

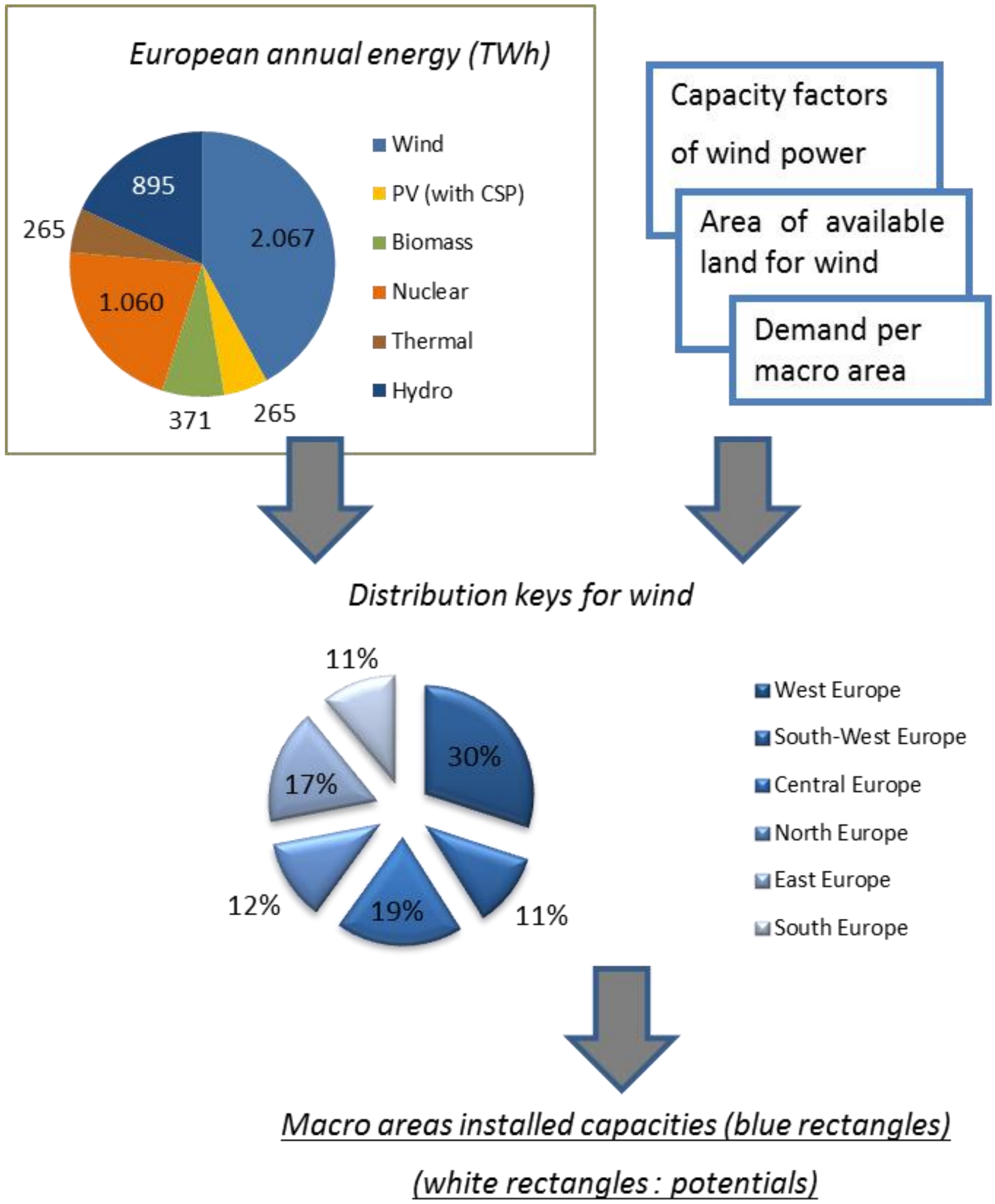

Figure 8: Downscaling from European to macro area level (wind generation)

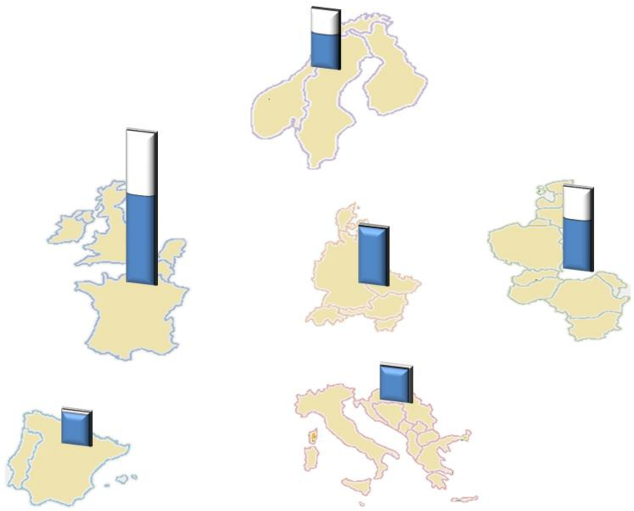

Figure 9: Initial determination of installed capacities per macro area

2.1.6. 4. Assessment of the need for extra capacity to ensure adequacy (macro area)

The installed capacities must be dimensioned in a form that the European demand can be covered in each hour. Hence, hourly system simulations without grid restriction are performed with ANTARES[2]. Indeed, it is expected that some RES generation will have to be spilled at some hours and that dispatchable units will probably lack power during hours with a high net demand. These two issues result in some energy not served and in less thermal and RES generation than expected over the year. To reach an acceptable level of adequacy and to stay close to the targeted energy mix, some increase of the generation capacities is thus required.

For this step, an algorithm using ANTARES is used. A first set of Monte-Carlo years (100, depending on the number of solar, wind and load time series) is simulated returning adequacy outputs, such as the Loss of Load Duration (LOLD). The LOLD is a quite convenient way to assess how far the system is from a reasonable adequacy. If the LOLD is higher than 3 hours, meaning that extra capacity is needed, incremental changes in installed capacities are then applied in the algorithm.

Simulations on ANTARES are performed again. This process is repeated until the adequacy criteria (LOLD<3h) is valid and unsupplied energy is low. Once all technologies have been increased, some storage is added to the system. Finally, if every bound has been reached and adequacy is still not met, peaking units are added at the end. These units are used a few hours per year but are necessary for adequacy. They represent either peaking thermal units or DSM. They are modelled in Antares as thermal units with high costs.

[2] ANTARES (**A** **N**ew **T**ool for **A**dequacy **R**eporting of **E**lectric **S**ystems) is a Monte-Carlo software for power systems analysis, developed by RTE. See Annex B for more details.

This process is illustrated in the following figure:

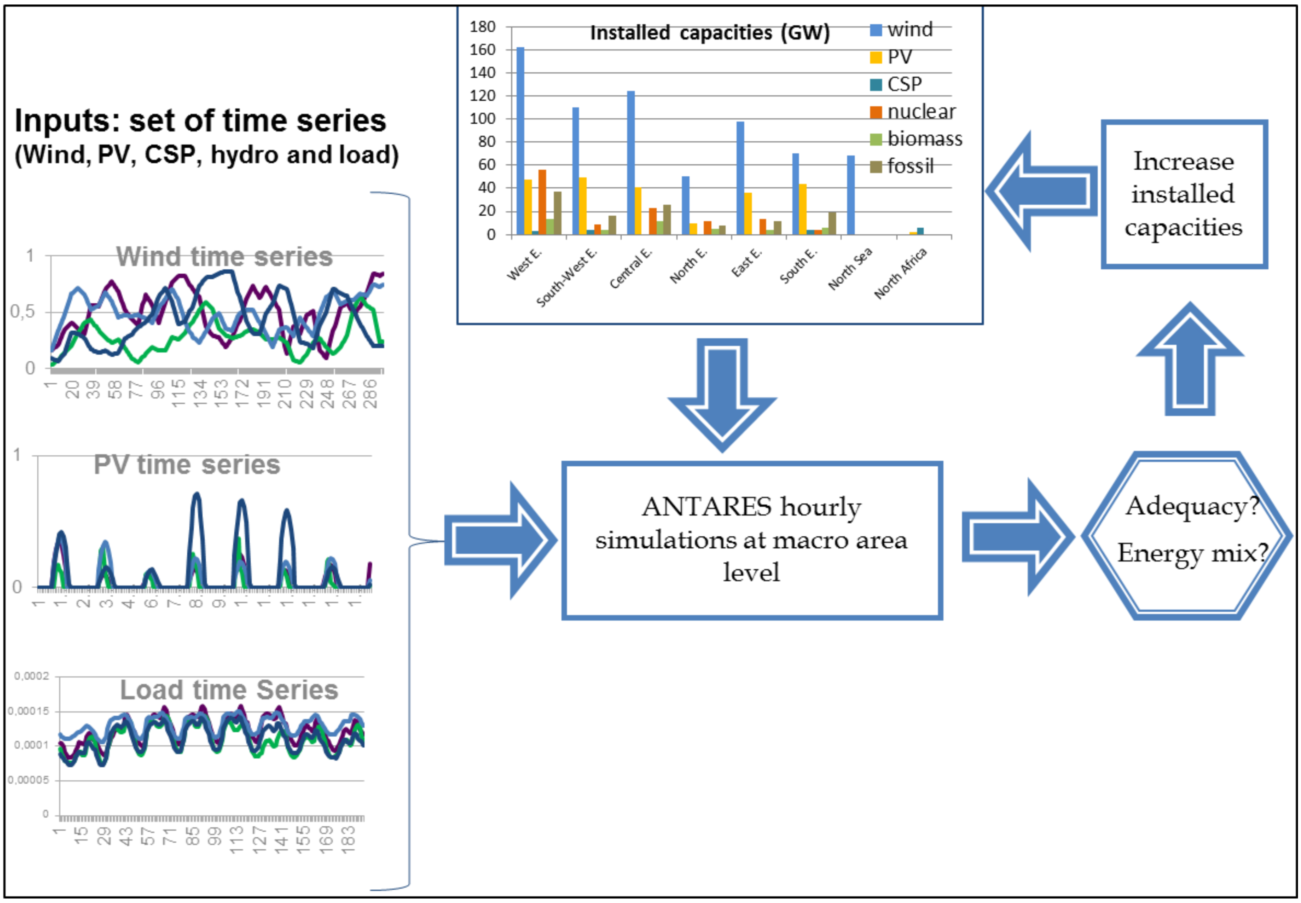

Figure 10: Schematic presentation of system adequacy analyses

2.1.7. 5. Check of inter macro areas imbalances

Imbalance is defined as the ratio between the generation and the demand of an area. For each scenario, a maximal acceptable imbalance per macro area and country was defined according to the description of the scenarios (see table 1 below). After simulations with Antares, if the maximal imbalance is not respected in some areas, some generation is redistributed.

Scenario	X-5	X-7	X-10	X-13	X-16
Accepted range of imbalances per macro area/ country	20%-180%	20%-180%	70%-130%	70%-130%	90%-110%

Table 2: Allowed imbalances per country in each scenario

2.1.8. 6. Distribution of installed capacities per technology into countries

On country level the same approach as on macro area level is used. At first, for each technology, distribution keys and potentials are calculated to distribute the macro level data among countries. In addition, 2020 targets of the countries are considered as minimal installed capacities for 2050 and national policies such as nuclear phase out are also considered.

A more detailed distinction of thermal units is done on country level. Thermal is split into hard coal, lignite and gas, with and without Carbone Capture Storage (CCS). To do so, the number of hour of use of thermal plants is analysed and the split between the different types of plants is done considering their level zed Cost of Energy (see chapter 3.6 for more details).

2.1.9. Sanity checks of the results (Steps 7 to 9)

Check of system adequacy (country level)

Demand side management is taken into account at this step: the demand time series are optimized daily to even the residual load (see chapter 3.1 for more details) Hourly system simulations are then run at country level. System adequacy is checked and if necessary extra capacities are installed (see chapter 2.15 as for macro area).

Check of inter countries imbalances

As for macro area level, countries imbalances are checked and some generation can be redistributed.

Distribution of installed capacities per technology into clusters

At cluster level, distribution keys and potentials are used to distribute the country installed capacities and the demand between the clusters while taking into account local constraints.
(Comment: For this step no further calculation to evaluate system adequacy have been made. It is planned to solve possible issues via grid development in further steps of the project).

2.1.10. Consultation

Finally, the results of the quantification process at country and cluster levels are submitted to TSOs and stakeholders for consultation. Their comments are included and a final simulation ensures that adequacy is still reached.

Chapter 3 will give a comprehensive description of the data base methodology and the input data gathered to use for the calculations performed.

3. Data base and input data

3.1. Yearly electricity demand

For each scenario, the following parameters were defined for 2050 in accordance with the scenarios descriptions in "D 2.1 G/D/E Scenarios 2050":

- Population per country
- GDP/capita per country
- New demand from transport per country
- New demand from heating per country
- Reduction of demand due to energy efficiency
- Network losses per country

These parameters were combined with today consumption per capita per country to compute the 2050 projections. This process is depicted in figure 11. Results per scenario and per country are given in Annex C as well as the full description of the method.

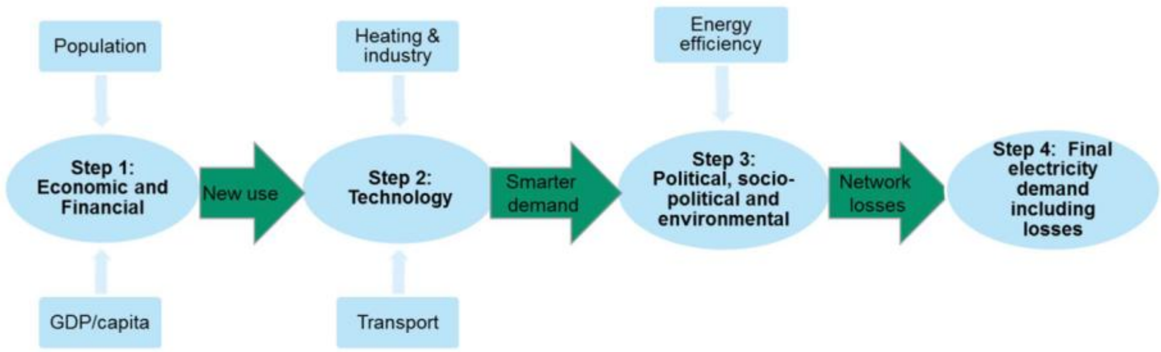

Figure 11: Process for projecting final annual electricity demand including network losses by country for 2050 in each e-Highway 2050 scenario[3]

More information on the database used and the intermediate results can be found in Annex C.

[3] For the purpose of these annual electricity demand projections, 'energy efficiency' refers to Passive Demand Side technologies – e.g. insulation in buildings or new components that consume less (new fridges etc.). Active demand side technologies are considered in the scope for changing the hourly time series of demand

3.2. Demand time series and demand side management

3.2.1. Methodology for time series development

The starting point for the 2050 time series for each country (across all 5 scenarios) are the **historical hourly demand profiles**. This historical data is provided by ENTSO-E and comes from **2010, 2011** and **2012**. Obtained data is normalized separately for each historical year and country. These normalized data is then scaled up to match country total energy consumption in 2050 excluding electric vehicles and new heat pumps. This fundamental demand profile for 2050 is increased by additional values resulting from new sources of demand, like **electric vehicles** and **heating**. The flow chart of the whole process is presented in figure 12.

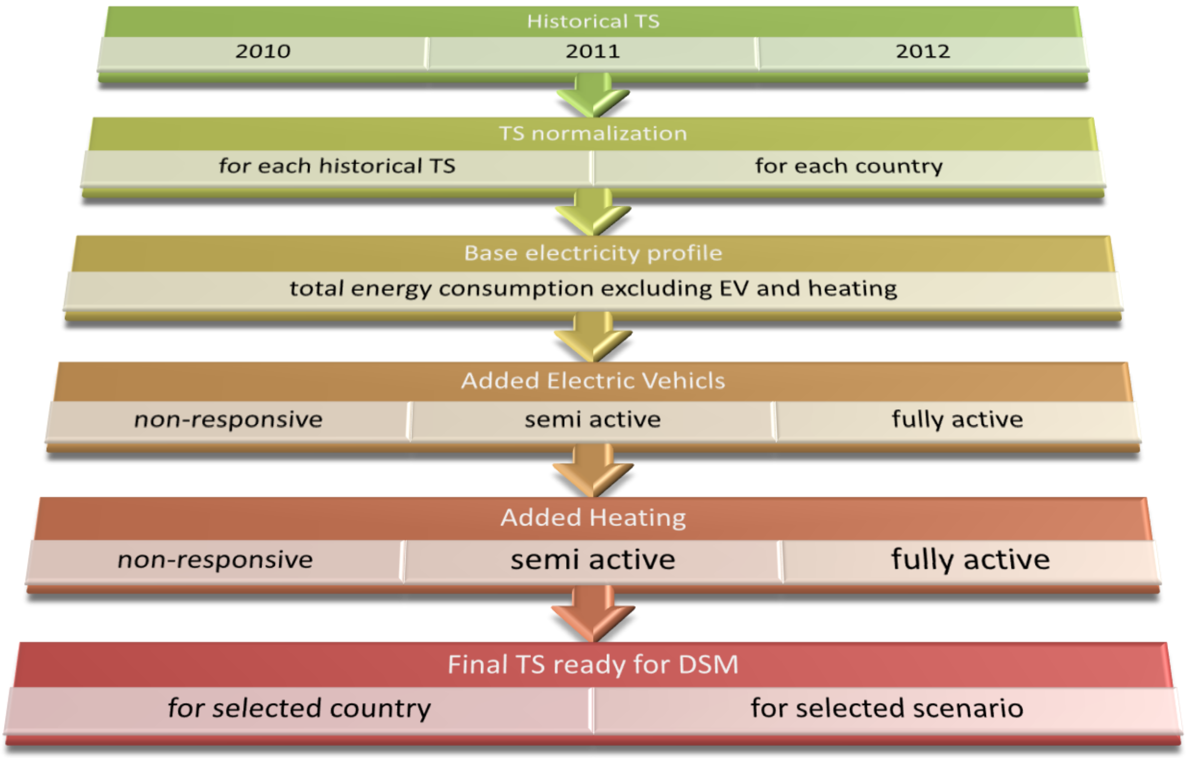

Figure 12: Demand TS for 2050 - methodology flow chart

Electric vehicles

Three types of electric vehicles with different flexibility are considered:

- non-responsive with a charging pattern based on driving patterns
- semi active following a smarter charging pattern (concentrated during the night) but not real-time responsive
- fully active, i.e. participating in demand side management. Their recharge is optimized each day to smoothen the residual load (see paragraph on demand side management)

The split between particular groups of EV demand depends on the scenario and is presented in Annexes C and E.

Heating

Heating demand is split between residential and non-residential heating. Within each group – residential and non-residential heating - the demand is then split again between water heating and space or technological process heating. Each type of heating has a different consumption pattern and a different potential of flexibility. Demand response is assumed to be mainly carried by water heating. As for electric vehicles, the demand for heating is split between:

- non-responsive demand (following a “natural” pattern)
- semi-active demand (no real-time responsive but following a smarter pattern, concentrated at night)
- fully active (see paragraph on demand side management)

See annexes C and E for more information

3.2.2. Demand side management

The high penetration of renewables and new uses of electricity will lead to a significant need for flexible demand by 2050. In this light, it seems likely that there will be a roll-out of *demand side management* systems by 2050. As a result, the residual demand will be smoother (leading to lower cycling costs), peak demands will be mitigated and surpluses will be lower. Therefore based upon the hourly time series of demand, which have been developed from yearly generation, as well as generation of RES, an optimization of demand is applied to flatten residual peak loads on country level. DSM is applied in Step 2 – country level – and installed RES capacities of step 1 – macro area level – are used to determine the generation of RES in each hour.

It is assumed that the following technologies participate in demand side management schemes:

- Fully active electric vehicles;

- Fully active Electric heating;
- Other appliances.

To take into account these appliances, a percentage of the total demand was considered as fully active: 0.5% for scenarios X-5, X-7, X-10 and X-13 and 1% for X-16.

In terms of modelling, the following procedure was developed. First, all Monte Carlo-combinations of the electric demand and non-dispatchable injections from RES are calculated on country level (3 demand time series x 11 RES time series = 33 combinations). Second, for each of these combinations an optimization algorithm is run. In this algorithm, the variance of the residual demand is minimized on a day-to-day basis, taking into account the technical constraints of each DSM technology (electric vehicles, heating or white goods). Last, this optimized combination of demand and RES profiles is used as an input for the ANTARES modelling environment.

The full description of the methodology to get demand time series including DSM can be found in Annex. An example of the impact of DSM is presented on the graph below:

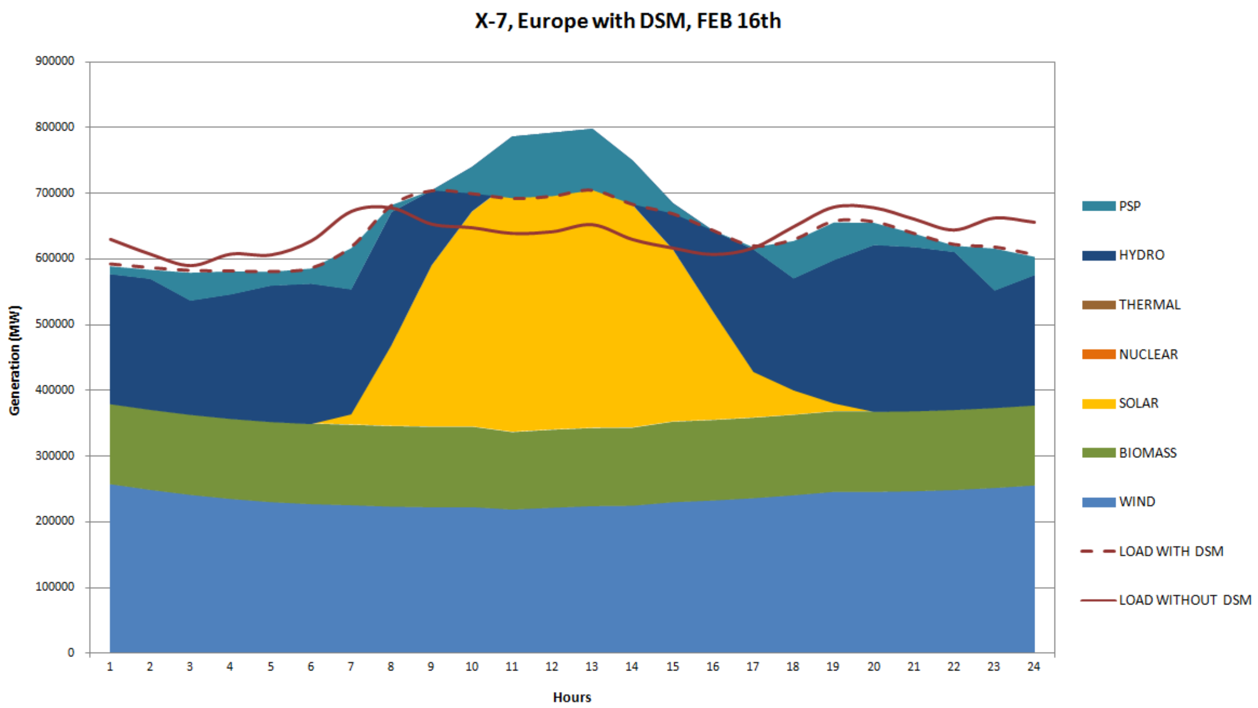

Figure 13: Example DSM – Scenario X-7

3.3. CO_2 limits and CCS potential

The European Commission target for 2050 is an 80% reduction of CO_2-emission over all sectors compared to 1990. In each “e-Highway 2050” scenario, different electrification assumptions of transport and heating have been made. This will imply different degrees of decarbonisation of the power sector. However, the worst case scenario is considered, where the other sectors have a very limited potential to reduce their GHG emissions. Thus, the common target of **95% of CO_2 emissions reduction by 2050** (compared to the 1990 level) is used for all scenarios, independently of the level of decarbonisation of other sectors. Thus, the electricity sector (EU-28 + Switzerland + Norway + Serbia + Bosnia and Herzegovina + Albania + Montenegro) emitted 1.46Gt of CO_2 in 1990, and the CO_2 emission target is **70Mt CO_2** by 2050.

Basically three technology options are available in a low or zero carbon system: RES, nuclear and fossil fuels with CCS. Carbon Capture and Storage (CCS) could help to make huge emissions cuts, but its maturity in 2050 is uncertain and thus assumed only in two scenarios (“X-10” and “X-13”).

The GeoCapacity project (2006-2009) assessed the European capacity for geological storage of CO_2 in EU countries. The total European storage capacity is supposed to be 360GtCO_2, with 326GtCO_2 in deep saline aquifers, 32GtCO_2 in hydrocarbon fields and 2GtCO_2 in un-mineable coal beds. The previous storage capacity can also be split into 116GtCO_2 of onshore storage and 244GtCO_2 of offshore storage (the GETSCO project (2003) evaluated that 200GtCO_2 of offshore storage would be in Norway). However, these storage sites are not equally exploitable. Thus, GeoCapacity calculated a more realistic storage capacity. This conservative storage capacity is estimated to be **117GtCO_2**. This value is the one considered in the e-Highway 2050 project when reference is made to the number of year of possible storage.

The CO_2 price assumed for the different scenarios is **270€/t.**

3.4. Data photovoltaic technology

3.4.1. Technical potential

Potentials per cluster (and then per country and macro area) should be computed in a common way for all the clusters to ensure consistency. Thus a simple and transparent method is applied. PV potential is split between building integrated PV and PV farms, each of them being computed separately as follows:

<u>Methodology for building integrated PV:</u>

The potential for building integrated PV is calculated with the following formula

Technical potential (W) =
(Standard roof area/capita [m²]) ***x*** *(Population)* ***x*** *(Estimated % of the roof suitable for PV)*
x *(Capacity density [W/m²] for PV)*

The standard roof area per capita is assumed to be 24m²/capita [PV-2] including roofs and façades, and the utilization factor (suitability of the area for PV) is assumed to be 0.4 [PV-2]. The value of the typical capacity density (W/m²) for PV is 151W/m² [PV-7].The population data is the estimated cluster population in 2030 [Eurostat data].

Methodology for PV farms:

Two different types of land are assumed to be suitable for PV: free land (semi natural areas such as grass-lands) and agricultural land. It is assumed that 0.1% of agricultural lands can be converted into PV farms, and 2% of the available free land can be covered by PV due to socio-geographical issues. The formula used to calculate the potential is then:

Technical potential =

*[(Free land [km²]) **x** (Acceptable % of free land covered by PV) **+** (Agricultural land [km²]) **x** (Acceptable % of agricultural land covered by PV)] **x** (Capacity density [GW/km²] for PV)*

The data on free land area and agricultural land area come from Corine Land Cover database (land use map). (PV potentials per cluster are in Annex F)

3.4.2. Distribution keys

Distribution keys are calculated for each macro area/country/cluster in order to split installed capacities from Europe to macro areas, then from macro areas to countries and finally from countries to clusters. It is assumed the distribution of RES installed capacities will not follow a fully economical optimization: even if a country has the most significant wind/solar resource in Europe, it is very unlikely that all the European generation capacity will be installed there. Each country and even each cluster will plan to have its own RES generation if wind/irradiance is still high enough to compensate the investment. This tendency will be stronger in the scenarios with a more “small and local” vision: generation will be as close as possible to demand. Thus the distribution keys are weighted averages of two factors: one represents the electricity demand in the area and the other is calculated from the capacity factor (CF) and the area of available land. A repartition only based on capacity factors would distribute the capacities where the resource (solar irradiation and available area) is the most important, whereas a repartition based on demand would place the capacity close to consumption.

The allocated weights depend on the spirit of the scenario.

The distribution keys are obtained as follows:

$$Distribution\ key\ (\%) = \frac{a \times Demand(\%) + b \times weighted\ CF(\%)}{a+b}$$

With:

$$Weighted\ CF\ (\%) = \frac{\left(\max_i(|\frac{CFi-\overline{CF}}{\overline{CF}}|) + \frac{CF-\overline{CF}}{\overline{CF}}\right) \times AvailableArea}{\sum_j\left(\max_i(|\frac{CFi-\overline{CF}}{\overline{CF}}|) + \frac{CFj-\overline{CF}}{\overline{CF}}\right) \times AvailableArea_j)}$$

Where CF is the average capacity factor of the country, $\overline{CF}$ the average capacity factor in the macro area, and $\max_i(|\frac{CFi-\overline{CF}}{\overline{CF}}|)$ is used to scatter the $\frac{CF-\overline{CF}}{\overline{CF}}$ values between 0 and 1. And *a* and *b* as selected weights per scenario:

	a (Demand)	b (weighted CF)
Large scale RES	1	10
100% RES	2	1
Big & Market	1	3
Large Fossil Fuel	1	3
Small & Local	10	1

Table 3: Weights of a and b for each scenario

PV distribution keys per macro area, country and clusters are presented in Annex G.

3.4.3. Time series

Time series are computed by using reanalysis data [5]. This database provides historical value of solar radiation and clearness index 4-times daily for a set of grid points. Based on these values, 24 generation values per day per cluster are computed [6]. It was done for eleven historical years.

3.5. Potential for Concentrated Solar Power (CSP) technology

3.5.1. Technical potential

To define potentials for concentrated solar power, the following methodology is applied:

1) Only clusters with an average Direct Normal Irradiation (DNI) ≥ 2,000 kWh/m²/year are supposed to be suitable for CSP. In the other clusters, the potential is set to zero.
   [source for DNI data: U.S. National Aeronautics and Space Administration (NASA), Surface meteorology and Solar Energy (SSE)]

2) For each of the remaining clusters, an area of land available for CSP is calculated from:

   Available land = [(Free land [km²]) x (Acceptable % of free land covered by CSP)
   + (Agricultural land [km²]) x (Acceptable % of agricultural land covered by CSP)]

The assumptions are that 0.1% of agricultural lands can be converted into CSP farms, and 2% of the available free land can be covered by CSP due to socio-geographical issues.

3) The concentrating system technical potential is deduced by the formula:

   Concentrating system technical potential = (Available land) x (Capacity density [W/m²] for CSP = 200 W/m²)

4) For CSP, the power of the concentrating system and the power of the turbine can be different due to storage. In the chosen model, with a storage capacity of 4 hours, the calculated solar multiple[4] from the time-series is 2.3. Thus, the final technical potential (turbines) is:

   Technical potential = Concentrating system technical potential / 2.3

Only five countries in Europe have regions where DNI is higher than 2000 kWh/m²/year: Spain, Portugal, Greece, France and Italy. The calculated potentials of CSP in these countries using this methodology are presented in the following table 3 (CSP potentials per cluster are in Annex F):

Country	CSP Potential (GW)
ES	50
FR	7
GR	11
IT	19

[4] "solar multiple" is the ratio between the power received from the sun by the collectors and the power generated by the turbine

PT	11

Table 4: CSP potentials per country (where DNI > 2000 kWh/m²/year)

3.5.2. Distribution keys

The distribution key is based on the difference between the average Direct Normal Irradiance (DNI) in the countries (where DNI > 5kWh/m²/day) of the same macro area and the DNI of the country. Then, this is multiplied by the available area of the country, so that the distribution keys will also depend on the available land size. Each country distribution key (where DNI > 5kWh/m²/day) is calculated as follows (the other countries, where DNI < 5kWh/m²/day, have a zero distribution key):

$$\textit{Distribution Key (\%)} = \frac{\left(\max_i(|\frac{DNIi-\overline{DNI}}{\overline{DNI}}|) + \frac{DNI-\overline{DNI}}{\overline{DNI}}\right)\times AvailableArea}{\sum\left(\max_i(|\frac{DNIi-\overline{DNI}}{\overline{DNI}}|)+\frac{DNI-\overline{DNI}}{\overline{DNI}}\right)\times AvailableArea}$$

Where *DNI* is the average DNI of the cluster, $\overline{DNI}$ the average DNI in the clusters of the same macro area (where DNI > 5kWh/m²/day), and $\max_i$ ($|\frac{DNIi-\overline{DNI}}{\overline{DNI}}|$) is used to scatter the $\frac{DNI-\overline{DNI}}{\overline{DNI}}$ values between 0 and 1.

Macro area and cluster distribution keys are calculated with the same method. CSP distribution keys per macro area, country and clusters are presented in Annex H.

3.5.3. Hourly modelling

PV time series are proportional to global irradiance, whereas CSP should depend on Direct Normal Irradiance (DNI). However, PV time-series are used to get the profile of “solar inflows” for CSP. This approximation is sufficient as only the variability of irradiance between days is extracted (CSP power generation is then smoothed each day). CSP is modelled with a flat profile instead of modelling the storage of each power plant. Indeed, a complete modelling takes significantly more computation time and is not required as the level of CSP in the scenarios is quite low. A 4-hour storage following the last solar inflow of the day is assumed, and a constant generation over the production period (daylight period + storage period).

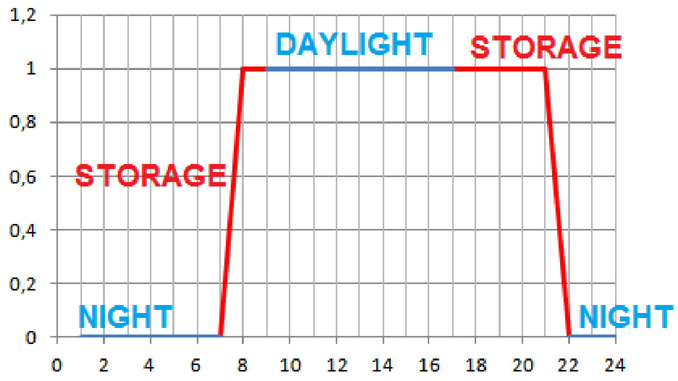

Figure 14: CSP daily generation pattern

3.6. Data for wind technologies

3.6.1. Technical potential

Onshore

Potentials per cluster (and then per country and macro area) should be computed in a common way for all the clusters to ensure consistency. Thus a simple and transparent method is applied.

Two different types of land are supposed to be suitable for wind turbines: free land (semi natural areas such as grasslands) and agricultural land. Urban areas, mountains and forests are excluded. The available lands with a mean wind speed lower than 5m/s are also excluded due to their low profitability.

As wind turbines do not use a lot of space, they can be installed on croplands, without impacting too much agriculture. Thus, it is assumed that **10%** of agricultural land and free land (with wind speed > 5m/s) can be covered by wind turbines, considering their spatial occupancy.

The potential is then calculated with the following formula:

Technical potential [MW] = [(Free land with wind speed > 5m/s [km²]) + (Agricultural land with wind speed > 5m/s [km²])] x (Acceptable % of land covered by wind turbines) x (wind turbines density (MW/ km²))

Due to expected efficiency improvements by 2050, it can be assumed that for wind potential, turbine density will increase to **7MW/km²** by 2050. The data on free land area and agricultural land area come from Corine Land Cover database.

Offshore

EEA calculated offshore potential area for wind energy generation [4]. Starting from this study, it is assumed that 3% of these potential areas would be available for wind farms. The technical potential in GW in each country was calculated using a turbine density of **15MW/km²** [4].

Technical Potential [GW] = 3% x (Potential Area (EEA) [km²]) x 0.015 [GW/km²]

Note: Offshore wind farms attached to clusters with coastlines bordering North Sea are gathered into the same cluster "North Sea" and not directly connected to their country. Consequently, the calculated offshore potentials in countries surrounding North Sea (United Kingdom, Netherlands, Denmark, Germany, Sweden and Norway) do not consider the following clusters: 94UK, 93UK, 92UK, 90UK, 26FR, 28BE, 30NL, 31DE, 38DK, 79NO and 81NO.[5]

The chosen offshore potential for North Sea is 135GW, which corresponds to the "Grand Design" scenario in the Windspeed project [Wind 5].

The calculated onshore and offshore wind potentials per cluster using this methodology are in Annex D.

3.6.2. Distribution keys

Distribution keys are calculated for each macro area/country/cluster in order to split installed capacities from Europe to macro areas, then from macro areas to countries and finally from countries to clusters. It is assumed that the distribution of RES installed capacities will not follow a fully economical optimization: even if a country has the most significant wind/solar resource in Europe, it is very unlikely that all the European generation capacity will be installed there. Each country and even each cluster will plan to have its own RES generation if wind/irradiance is still high enough to compensate the investment. This tendency will be stronger in the scenarios with a more "small and local" vision: generation will be as close as possible to demand.

Thus distribution keys are weighted averages of two factors: one represents the electricity demand in the area and the other is calculated from the capacity factor and the area of available land. A repartition only based on capacity factors would distribute the capacities where the resource (wind speed and available

[5] A graph of the European Cluster model with the localization of all clusters is given in Annex A

area) is the most important, whereas a repartition based on demand would place the capacity close to consumption.

The allocated weights depend on the type of scenario. Distribution keys are obtained as follows:

$$Distribution\ key\ =\ \frac{a\ \times\ Demand(\%)\ +\ b\ \times\ weighted\ CF(\%)}{a+b}$$

With:

Weighted CF (%) =

$$Weighted\ CF\ (\%)\ =\ \frac{\left(\max\limits_{i}(\left|\frac{CFi-\overline{CF}}{\overline{CF}}\right|)+\frac{CF-\overline{CF}}{\overline{CF}}\right)\times AvailableArea}{\sum\left(\max\limits_{i}(\left|\frac{CFi-\overline{CF}}{\overline{CF}}\right|)+\frac{CF-\overline{CF}}{\overline{CF}}\right)\times AvailableArea}$$

Where *CF* is the average capacity factor of the country, $\overline{CF}$ the average capacity factor in the macro area, and max ($|\frac{CF-\overline{CF}}{\overline{CF}}|$) is used to scatter the $\frac{CF-\overline{CF}}{\overline{CF}}$ values between 0 and 1.

And *a* and *b* as selected weights per scenario:

	a (Demand)	b (weighted CF)
Large scale RES	1	10
100% RES	5	8
Big & Market	1	3
Large Fossil Fuel	1	5
Small & Local	5	1

Table 5: Weights of a end b for each scenario

Macro area and clusters distribution keys are calculated with the same methodology. Wind distribution keys per macro area, country and clusters are presented in Annex I.

3.6.3. Time series

Time series are computed by using reanalysis data [PV-5]. This database provides historical values of wind speed 4-times daily for a set of grid points. Based on these values, 24 generation values per day per cluster are computed [PV-6]. It is done for eleven years.

3.7. Data for thermal technologies

3.7.1. Types of units and modelling

The different types of fossil thermal units considered in WP2 simulations are:

- Hard coal without CCS
- Hard coal with CCS
- Lignite without CCS
- Lignite with CCS
- Gas CCGT without CCS
- Gas CCGT with CCS
- Gas OCGT
- Nuclear

A selection has been down to identify these technologies as suitable thermal technologies for future investments in generation capacities. Oil power plants have been left aside since their operational expenses and marginal costs of generation are considered as being too high.

Thermal plants are modelled in the system simulator (Antares) with the following parameters: marginal cost, maximal power, minimal power, minimum up and down time, planned and forced outages rates and durations. Their generation is optimized to minimize the overall cost of the system. The details of these parameters to model thermal units in the System Simulation can be found in Annex E, they are mainly from WP3 database.

3.7.2. Technical potentials and distribution keys

Technical potential of thermal plants is virtually infinite. However, potentials are defined for the quantification process to make sure that social limits are not exceeded, especially for nuclear. They are set to high but realistic values:

- For nuclear, countries potentials are set to 150% of the installed capacity considered in TYNDP vision 4, except for Switzerland where potential is set to 0 as a nuclear phase-out was decided. Countries with no nuclear in TYNDP vision 4 have no nuclear potential.
- For Fossil plants, countries potentials are set to 150% of the installed capacity considered in TYNDP vision 1

Distribution keys for nuclear and fossil plants are defined as weighted average of: demand distribution and today plants distribution.

3.7.3. Share of the fossil generations in the thermal installed capacities

The first steps of the quantification process estimate the necessary installed capacity of fossil plants per macro area. Then, this installed capacity is split between the different types of plants and is distributed among the countries of each macro area.

Four parameters were considered for that:

- **Scenario description**
  According to the description of the scenario (D1.2), CCS technologies are not mature in X-5 and X-16.

- **LCOE and duration curve of the thermal generation resulting from the first simulations**

  The levelised cost of electricity (LCOE) is the cost of each MWh including fixed costs (investment, fixed operation and maintenance cost) on the contrary to marginal cost. The LCOE of a technology strongly depends on the average annual generation: the more MWh are produced per year, the less the investment costs impact the price of the MWh. As a result, technologies with a high investment cost (for example plants with Carbone capture storage) are competitive only if they run a significant number of hours per year. The LCOEs of the different types of plants has been calculated for all the scenarios and three ranges of profitability are defined:

  - For less than 100 hours of use per year, it is assumed that only OCGT are profitable and flexible enough
  - Between 100 hours and 1000 hours, CCGT without CCS is the most profitable technology
  - For more than 1000 hours, the profitable technologies depend on the scenario :
    - For X-5 and X-16: CCGT without CCS is the most profitable. However, lignite and coal without CCS are considered as profitable as well because their LCOE is very close.
    - For X-10 and X-13: CCGT with CCS, lignite with CCS and coal with CCS have very similar LCOE. All of them are considered. On the contrary lignite and coal without CCS are really too expensive and are considered as not available in these scenarios.

  For each scenario, the duration curves of thermal generation are analysed to define the share of the different units in the thermal installed capacity. Thus, their profitability is ensured.

- **2030 share of the different technologies in the installed capacities of the countries**

The choice between coal, lignite and gas depends on the country resources. For example, some countries have significant resource of cheap lignite. To take these aspects into account, for each country, the respective shares of gas, coal and lignite are based on the 2030 values assumed for the TYNDP.

- **CO_2 emissions limit**
  The annual CO_2 emissions should be below 70Mt to reach the reduction targets. For scenarios with and without CCS (X-10 and X-13), the emissions are directly correlated to the shares with/without CCS. CCS being a technology with a lot of uncertainty, its share in the energy mix is limited when it is possible without over passing the CO_2 emissions limit.

3.8. Data solar in North-Africa

Assumptions of imports from North Africa were mainly based on studies by the Desertec Industrial Initiative (Dii): Desert Power: Getting started, the manual for renewable electricity in MENA, June 2013.

3.8.1. Interconnections between North Africa and Europe

Morocco, Tunisia, Algeria, Libya and Middle East are assumed to be connected and exporting energy to Europe. The interconnections between Europe and these countries are out of the scope of the e-Highway 2050 study, it will be assumed that they are already in service. The considered interconnections graph is:

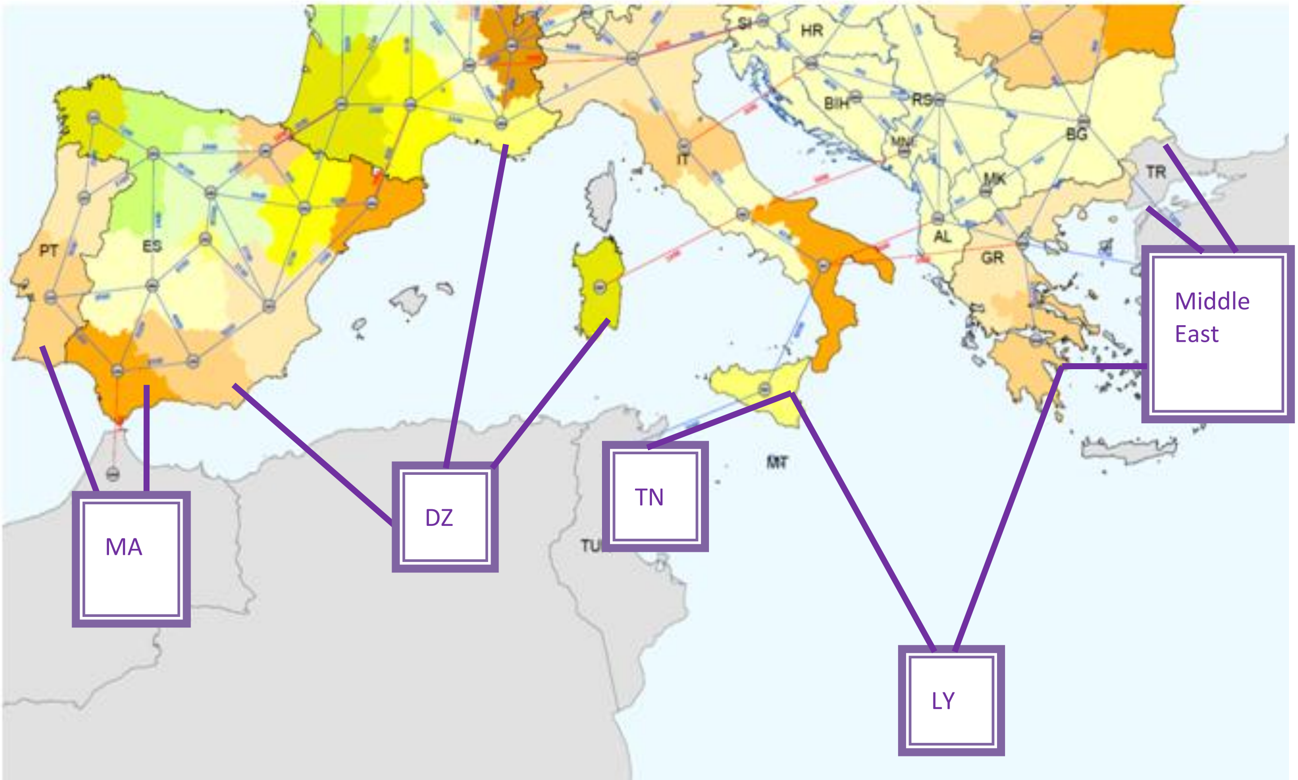

Figure 15: Exchanges with North Africa

3.8.2. Annual imports from North Africa to Europe

In the description of the scenarios, high imports from North Africa are assumed in X-5 and X-7. For X-10 and X-16, imports are said to be "medium". For X-13, imports are supposed to be low. According to this description, the annual imports from North Africa to Europe are set to the following values:

Scenario	**Annual Import (TWh)**	**European demand (TWh)**	**% of European demand**
X-5 Large Scale RES	374	5356	7%
X-7 100% RES	131	4374	3%
X-10 Big and Market	43	4376	1%
X-13 Large CCS and Nuclear	0	4842	0%

X-16 Small and Local	31	3153	1%

Table 6: Annual energy imports from North Africa per scenario

These exports are distributed between North African countries according to Dii assumptions.

3.8.3. Modelling in System Simulations

Only the share of North Africa solar generation (PV and CSP) which is dedicated to export to Europe is considered. 70% of the installed capacity is assumed to be CSP and 30% PV. PV and CSP generation in North Africa are modelled as PV and CSP generation in Europe. The following installed capacities per country are assumed:

Installed capacity - Europe (MW)	X-5		X-7		X-10		X-13		X-16	
	PV	CSP	PV	CSP	PV	CSP	PV	CSP	PV	CSP
MA	8 300	19 300	2 900	6 800	1 000	2 300	0	0	700	1 600
DZ	15 700	36 600	5 500	12 800	1 800	4 300	0	0	1 300	3 100
TN	2 600	6 100	900	2 100	300	700	0	0	200	500
LY	7 500	17 600	2 600	6 200	900	2100	0	0	600	1500
Middle East	800	1900	300	700	100	200	0	0	100	200
TOTAL	34 900	81 500	12 200	28 600	4 100	9 600	0	0	2 900	6 900

Table 7: Installed capacities – Solar in North Africa

3.9. Data for biomass

3.9.1. Technical potential

Two types of biomass are distinguished within the project:

- "Biomass 1": It is composed of local and pre-existing resources mostly waste (domestic and agricultural waste, forest residues). This biomass is assumed to be cheap but with a limited potential.

The 7th framework Bioboost project has estimated the potential for biomass, excluding energy crops, for the NUTS-3 regions of Europe. These potentials were used to calculate the potentials per clusters of Biomass 1. (See in Annex J for values per country)

- "Biomass 2": It is composed of dedicated energy crops and biomass imports. Thus, biomass 2 is assumed to have a very high potential but higher cost. During the quantification process, biomass plants exceeding the biomass 1 potential are considered as biomass 2 plants.

3.9.2. Distribution keys

The distribution keys of Biomass are defined by a weighted average of two distributions:

- Demand distribution
- Biomass potential distribution

The weights depend on the scenarios as follow:

	Demand	Potential
Large scale RES	1	5
100% RES	1	1
Big & Market	1	1
Large Fossil Fuel	1	1
Small & Local	5	1

Table 8: Weighting factors Biomass

3.9.3. Modelling and costs

Biomass plants are modelled as fully dispatchable plants, like nuclear and fossil plants. The modelling parameters of biomass are detailed in Annex K.

3.10. Data for hydraulic generation and storage

3.10.1. Run of river and hydraulic with reservoir: potentials and distribution

Questionnaires were sent to TSOs to collect data for 2012 and 2030 for: RoR units, HPPs with reservoirs and PSPs. For the countries without data provided by TSO, ENTSOE publicly available data are used.

At macro area level, the 2030 data are scaled up to reach the hydro generation target of each scenario while checking the potentials defined in [Eurelectric] are not exceeded.

Distribution from macro area to country level is based on the country potential/macro area potential ratio for X-5 and X-7. For other 3 Scenarios, it is based on the country 2010 status/macro area 2010 status (EURELECTRIC). Each country volume is limited to its potential defined in EURELECTRIC document.

Distribution between clusters is made according to information from TSOs. When TSOs data is not available, public sources (Enipedia, Global Energy Observatory) about the today localization of hydro generation are used.

3.10.2. Run of river and hydro with reservoir: modelling

Run of river generation is modelled as fixed infeed time series, at an hourly scale. Three time series are used for the monte-carlo simulations: dry, average and wet year.

Hydro with reservoir generation is optimized by the simulator from three modelling inputs: monthly inflows, maximal power and size of the reservoir. Three inflows time series are used for Monte-Carlo simulations: dry, average and wet year.

3.10.3. Pumped storage plants

Storage capacity (GW) in 2030 in each country is calculated on the basis of Eureletric database, as the sum of existing, licensed and planned plants, reaching 73 GW for the whole Europe (see Annex). This storage capacity is assumed as the level that will be, at least, reached in all Scenarios. The plants are distributed between clusters according to TSOs information or similarly to hydro with reservoir plants when no TSOs data is available. PSP are modelled as storage units with a maximal power, a size of reservoir and an efficiency of 75%.

Chapter 4 provides a detailed description of the 5 selected scenarios, explaining their respective general characteristics, their quantification performance, a sanity check and their evaluation and impact regarding the e-Highway 2050 study.

4. Results of the quantification process per scenario

4.1. Introduction demand assumptions

As described in the methodology part, the first activity of the scenario quantification process is to assess the yearly volume of demand for all scenarios. Yearly demand data for each country and scenario can be found in Annex.

Scenarios	Annual demand (TWh)
X5 large Scale RES	5364
X7 100%RES	4381
X10 Big and market	4387
X13 Nuclear and CCS	4854
X16 small and local	3161

Table 9: Annual European demand for the 5 scenarios

4.2. Scenario X-5 - Large scale RES and low emissions

4.2.1. General description

In this Scenario, a European agreement for climate mitigation is achieved and fossil fuel consumption is generally low worldwide. Therefore, fuel costs are relatively low. On the other hand, the CO_2 costs are high due to the existence of a global carbon market. The EU's ambition for GHG emission reductions is achieved: 80-95% GHG reduction.

The strategy focuses on the deployment of large-scale RES technologies, e.g. large scale offshore wind parks in the North Sea and Baltic Seas as well as the Desertec project in North Africa. A lower priority is given to the deployment of decentralized RES (including CHP and Biomass) solutions.

Similarly, a high priority is given to the development of centralized storage solutions (pumped hydro storage, compressed air, etc…) which accompanies the large-scale RES deployment. Decentralized storage solutions are considered to be insufficient to support the large-scale RES deployment: they are not given priority.

Nuclear technology as a centralized technology is included in this Scenario. Yet, no development in new nuclear technologies is assumed: the current level of deployment is maintained according to standard decommissioning rates for present nuclear plants up to 2050. Since only Europe has a strong policy for the reduction of GHG emissions, CCS technologies are not mature enough (high cost): they are not among the options to reach GHG reduction targets.

Electrification of Transport, Heating and Industry is considered to occur both at centralized (large scale) and decentralized (domestic) level. However, the political focus is mainly on the supply side: large amount of fossil-free generation will make investments in energy efficiency solutions less attractive. A low increase in energy efficient solutions is foreseen (including DSM and flexibility of EV use). Moreover, a clear shift towards 'greener' behaviours is experienced compared to e.g. present practices (focused and active involvement towards more energy efficiency, focused and active involvement towards more use of sustainable energy by the European citizen).

A convergent and strong policy framework for the whole European Member States is in place: the deployment of the available RES potential is possible everywhere. Common agreements/rules for transnational initiatives regarding the functioning of an internal EU market, EU wide security of supply and coordinated use of interconnectors for transnational energy exchanges exist.

Little attention paid to large-scale solutions which lowers the priority for imports of fossil fuels at EU level. As a consequence, Europe's energy dependence is low. However, a high import of RES from North Africa – Desertec project is included.

Compared with others, this scenario envisages the highest electricity demand to be supplied by large scale centralized RES solutions.

Expectations and guidelines on quantification process

The high scenario description foresaw an energy system containing of large scale production sides for renewable energy, which is transported to the consumption areas. This means an allocation of installed capacities according to efficiency factors. Expected are therefore high International exchanges of energy. A significant import from Northern Africa (8%) and North Sea (8%) will be one backbone of the energy supply of Europe. This is expected to causes high imbalances that can reach up to 80%.

Due to diversified generation mix and relative high share of committable technologies, Security of supply isn't expected to be a critical issue.

4.2.2. Quantification performance

European level

Scenario X-5 gives the advantage to wind, hydro and nuclear solutions. PV is generally installed in North Africa, less in Europe and this provokes high power import in addition to also high power import of wind energy from North Sea. Nuclear units are also foreseen as a key contributor to reduce CO_2 emission since no CCS technologies are considered in this Scenario.

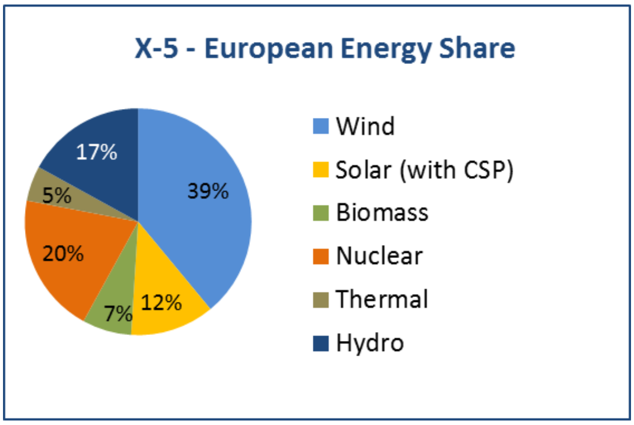

Figure 16: Detailed energy mix for quantification - X-5

Other technologies, like thermal are used to secure the system adequacy. European demand is the highest in this Scenario and reaches 5.300 TWh, due to high share of new use of electricity and low energy efficiency measures. Macro area values presented below are those before country quantification and consultation.

Macro area

Macro area values presented below are those before country quantification and consultation

a) Macro area level: initial results based on distribution keys

Based on distribution keys reflecting demand, capacity factors or expected levels of different technologies, energy mix and corresponding installed capacities are distributed per macro area. At the same time, potentials as maximum values are respected. The resulting installed capacities per macro area are presented in the table 9 below:

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total
Wind	209.179	78.923	136.717	80.751	118.240	85.935	103.700	813.445
Solar [PV+CSP]	54.328	56.366	80.545	43.466	18.000	3.609		256.314
Biomass	18.250	7.000	15.500	7.750	15.000	6.250		69.750
Nuclear	99.200	8.000	13.200	0	27.200	9.600		157.200
Thermal	98.900	36.550	61.300	47.200	19.900	4.000		267.850

Table 10: Initial capacities for scenario quantification - X-5

In hourly simulations, this set of installed capacities results in an average of **2260 hours of loss of load per year.** The main reason for adequacy problems is the lack of thermal units. At first, a use rate of 80% was assumed for thermal units to calculate the installed capacities. In hourly simulations, the real use rate is much lower resulting in lack of power in some hours and fossil annual generation lower than expected.

- ➔ These initial results have been used to run the semi-automatic optimization algorithm. Within this process capacities were re-allocated and increased to assure system adequacy and energy targets on macro area level for this scenario. As a binding constraint the imbalances of the macro areas were limited to the value assumed for the scenario - ±80%.

b) Macro area level: results after running the algorithm

The installed capacities at macro area level, before country quantification, are presented in figure 14 and the energy mixes as well as the balances of macro areas are shown in figure 15.

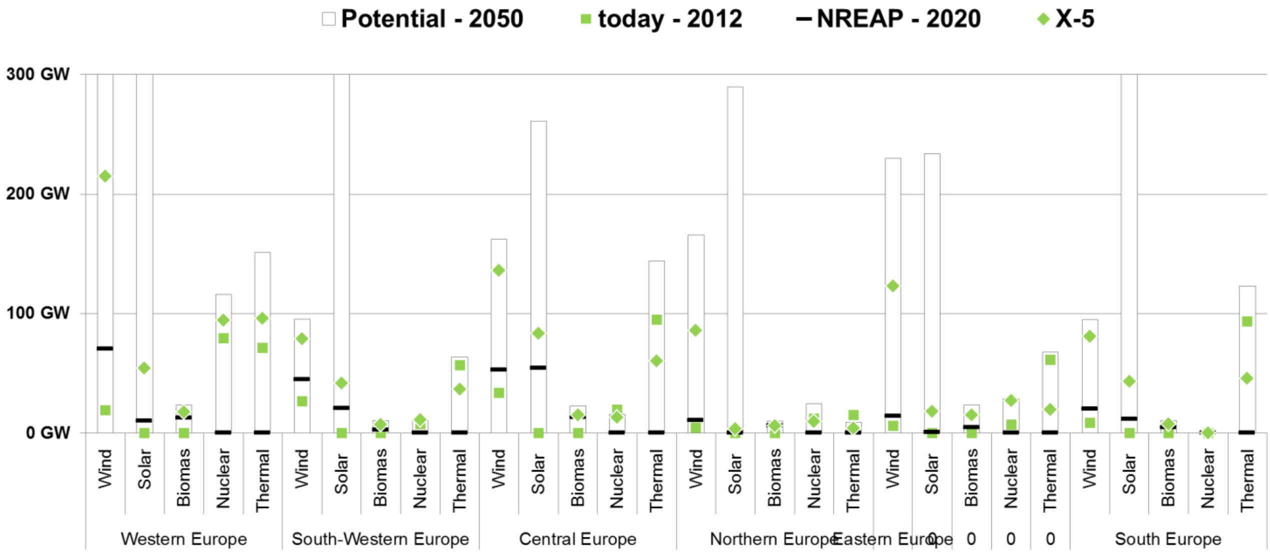

Figure 17: Intermediate installed capacities on step macro area – X-5

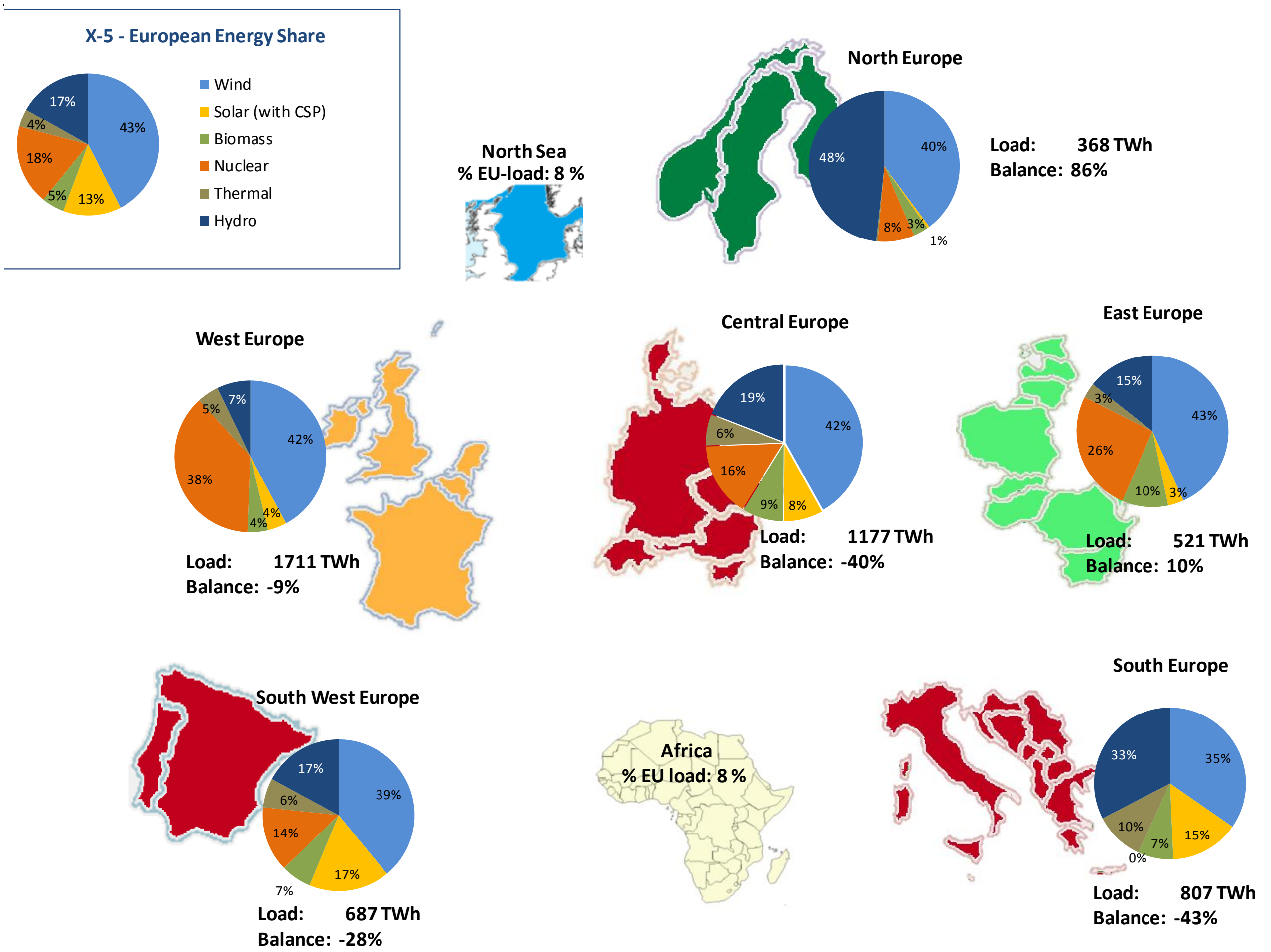

Figure 18: Intermediate energy mix on step macro area – X-5

The main conclusions in terms of installed capacities at macro area level for whole Europe are:

- Wind capacity must be increased by a factor of 4 compared to NREAPS 2020
- Nuclear capacity must be increased by 1.2 compared to today
- Hydro capacity must be increased by a factor of almost 2 compared to today
- PV capacity must be increased by a factor of 2.2 compared to NREAPS 2020
- CSP capacity must be increased by a factor of 1.8 compared to NREAPS 2020
- Thermal capacity must be decreased by a factor of 3.7 compared to today

The main conclusions concerning energy mixes and imbalances at macro area level for whole Europe are:

- Energy mix described in the scenario for each technology is respected
- Required level of imbalances is respected (< 80%), with minor deviations
- North Sea and North Africa are important source for energy for Europe
- High power exchanges are required

- Periods with low RES-production are “bridged” by fossil fuels & Biomass
- High flows from North Europe and North Sea to Central Europe, as well as from North Africa to South and South Western Europe are expected
- Wind is the most important RES source that supply 40% of total European demand

In Scenario X-5, CO_2-emissions are expected to be above the target of 70 Mtons of CO_2 per year. Thermal generation is about 250 TWh and since no CCS is foreseen to be available, emission is expected around 80 Mtons per year. This level of CO_2 emission presents reduction of 92 or 93%, instead of 95%, which is acceptable for this scenario with highest demand, high level of new uses of electricity and no CCS.

Country level

a) Country level: results before consultation

The installed capacities, as obtained on macro area level, were distributed over the various countries within each macro area according to a set of scenario-dependant distribution keys.

Moreover, the ‘thermal units’ considered at macro area level are now split between OCGT, CCGT, coal and lignite fired power plants, based on the duration curve of use over one year and the CO_2 emission limitation of 70 Mt per year. At this moment, the demand side management optimization is taken into account as well.

➔ These initial results are used to run the semi-automatic optimization algorithm. Within this process capacities are re-allocated and increased to assure system adequacy and energy targets on country level for this scenario. As a binding constraint the imbalances of the macro areas are limited to the value assumed for the scenario - ±80%.

In this scenario, 37 250 MW of peaking units (OCGT) are required to ensure adequacy. These units are used less than 100 hours per year in copper plate simulations.

b) Country level: final results after consultation

The resulting set of installed capacities has been submitted to TSOS and stakeholders for consultation. Feedback has been included and a last Antares simulation has been run to re-check adequacy. The final results at country results are presented in the table 10 below:

Country	**Wind (MW)**	**Solar [PV + CSP] (MW)**	**Biomass (MW)**	**Nuclear (MW)**	**Thermal (MW)**	**Demand (GWh)**	**Balance (%)**

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (GWh)	Balance (%)
AL	2.421	850	0	0	0	15.030	121,0%
AT	6.875	7.226	1.250	0	5.250	93.481	94,0%
BA	2.599	921	250	0	0	15.545	175,0%
BE	10.901	8.421	3.500	0	18.500	148.476	51,0%
BG	4.403	3.296	1.750	1.600	2.300	38.990	115,0%
CH	1.382	10.500	1.250	0	3.500	81.731	77,0%
CZ	10.279	3.925	500	11.200	3.800	87.873	120,0%
DE	98.600	54.428	9.000	0	45.000	815.155	44,0%
DK	18.492	2.606	3.000	0	2.250	52.246	131,0%
EE	8.244	409	250	0	1.000	15.292	133,0%
ES	67.448	50.822	6.000	8.000	31.800	609.826	70,0%
FI	37.198	1.505	3.000	3.200	3.000	101.119	139,0%
FR	84.219	33.090	6.750	72.000	17.300	795.247	106,0%
GR	25.861	8.266	1.500	0	1.000	83.072	126,0%
HR	6.255	882	250	0	1.000	29.295	79,0%
HU	4.889	3.127	2.500	6.400	2.000	72.459	102,0%
IE	15.479	258	500	0	6.250	52.759	105,0%
IT	41.293	30.252	5.500	0	41.900	528.236	48,0%
LT	14.959	529	750	1.600	2.500	34.344	148,0%
LU	617	121	250	0	1.000	9.041	53,0%
LV	13.709	425	750	0	1.000	25.690	146,0%
ME	520	616	0	0	0	3.943	287,0%
MK	371	443	0	0	500	10.333	63,0%
NL	14.993	6.173	3.000	1.600	23.300	196.805	46,0%
NO	13.048	480	250	0	500	124.918	194,0%

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (GWh)	Balance (%)
PL	62.521	3.807	4.750	9.600	5.800	210.883	97,0%
PT	11.474	5.544	1.000	0	4.750	86.870	86,0%
RO	4.818	5.404	3.250	4.800	4.300	83.587	120,0%
RS	1.429	1.235	250	0	2.800	38.439	60,0%
SE	35.689	1.624	3.000	6.400	500	146.446	143,0%
SI	472	1.739	250	2.000	500	18.294	144,0%
SK	4.697	1.004	1.000	3.200	1.000	32.497	119,0%
UK	83.587	6.386	4.500	25.600	33.550	537.632	99,0%

Table 11: Final installed capacities by technologies and balances on country level – X-5

The main conclusions from country level are:

- Countries with a high hydro potential and/or no nuclear phase out tend to be exporters: Finland, Norway, Sweden, France, Romania, and Greece.
- Italy, Germany, Spain, Belgium and Switzerland are the countries with the most critical imbalances.
- Before taking into account the NREAPS 2020, the distribution keys of PV in Germany lead to a significant lower value.
- Nuclear had to be slightly reduced in Central Europe as it was only installed in Slovenia and Czech republic.
- Demand side management was able to mitigate the problems of adequacy and peaking units with total 37 GW (OCGT) is needed to assure system adequacy.
- CO_2 emission are: 97 Mt

<u>Cluster level</u>

Based on distribution keys, installed capacities for each technology are distributed per clusters within each country. Potentials as maximum values are respected. Values on cluster level, after consultation, can be found in Annex.

4.2.3. Conclusion and evaluation

Major technology is wind: Wind installed capacity is very high: 968 GW including 104 GW from North Sea. It requires a lot of investment compared to 2020 targets (installed capacity should be more than 4 times higher). Second important technology is nuclear: The European installed capacity of nuclear is similar to today level. However, the installed capacities per country have to be increased in the countries without nuclear phase out to mitigate the phase out in Germany, Belgium and Switzerland.

Third important technology is hydro: The European hydro generation reaches its potential (900 TWh) and also PSPs are at maximum – 96 GW providing balancing services to high intermittent generation structure of the European system.

PV plays a less significant role in Europe (232 GW, 2 times higher than 2020 targets) but the investment for solar deployment in North Africa is quite high (116 GW). Biomass is even less significant, which is fully in line for Scenario X-5 with focus on large scale RES. Total biomass capacity is 69 GW.

Balances for macro areas are within thresholds set ex ante to the quantification tasks. However it can be observed, that significant exports from northern Europe and North Africa to the areas in central, south and south-west Europe are needed. Meanwhile the regions of Western and Eastern Europe are almost self-supplying. In general a high need for cross-European power-flows can be derived.

Security of Supply can be assured through committable units supported by storage and peak units. This also explains a relative low value of spilled energy (<1% of total European demand).

Carbon capture storage is not applied in this Scenario and this jeopardizes the achievement of the EC target of CO_2 reduction. Expected CO_2 reduction is 92% (instead of 95%), but still reasonable for X-5 scenario which is with highest demand, high level of new uses of electricity and low level of energy efficiency measures. Out of 263GW of thermal plants, 250 GW are gas without CCS, 7GW hard coal without CCS and 6GW lignite without CCS.

4.3. Scenario X-7 - 100% RES

4.3.1. General description

In this Scenario, the global community has not succeeded in reaching a global agreement for climate mitigation. Yet, Europe is fully committed to its target of 80-95% GHG reduction and the CO_2 costs in EU are high due to these strict climate mitigation targets.

The strategy to achieve this target has a higher ambition than the other scenarios: it bases Europe's energy system entirely (100%) on renewable energy. To reach this target, both large scale and small-scale options are used: offshore wind parks in the North Sea and Baltic Seas and the Desertec project in North Africa, combined with EU-wide deployment of de-centralized RES (including CHP and Biomass) solutions.

Public attitude towards the deployment of RES technologies is very positive in the whole Europe, while attitude towards nuclear and shale gas is negative.

Neither nuclear nor fossil fuels with CCS are used in this Scenario. Thus, both centralized storage solutions (pumped hydro storage, compressed air, etc…) and de-centralized solutions are needed to balance the variability in terms of renewable energy generation.

On the consumer side, a marked increase in energy efficiency (including DSM and flexibility of EV use) is also needed. Electrification of transport, heating and industry is considered to occur both at centralized (large scale) and de-centralized (domestic) level and these solutions will reduce resulting energy demand as well as provide complementary flexibility and storage to account for variability of RES production from PV and wind. There is a strong drive towards 'greener' behaviours in the population with active involvement towards more energy efficiency, more use of sustainable energy and clean transport etc.

As part of the 100% RES strategy, no import of fossil fuels occurs. Only renewable sources (solar energy from Africa, biomass from FSU region etc.) are imported from outside EU.

Compared with others, this scenario provides the most challenging conditions for the 2050-time horizon. The European energy mix will be based on 100% RES.

Expectations / guidelines on quantification process

The high scenario description foresees 100 % energy from renewable energy sources. The only considered committable technology is Biomass; therefore problems with Security of Supply are expected. Due to high installed capacities of wind and solar a high amount of spillage is expected because there will be hours with more generation than load and not enough storage to store the energy. Furthermore high imbalances and transportation requirements between macro areas are expected.

4.3.2. Quantification performance

European level

The targeted energy mix of the X-7 at European level is shown in the graph below. Wind will be the most important energy source. Hydro and Biomass have to be used as (partly) controllable units to face intermittency of renewable energy sources. European demand is 4329 TWh which, compared to other scenarios, is neither high nor low.

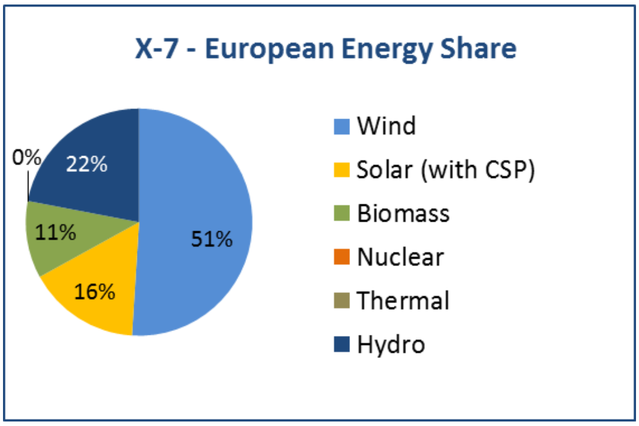

Figure 19: Detailed energy mix for quantification - X-7

Macro area

Macro area values presented below are those before country quantification and consultation

a) Macro area level : initial results based on distribution keys

Based on distribution keys reflecting demand, capacity factors or expected levels of different technologies, energy mix and corresponding installed capacities are distributed per macro areas. At the same time, potentials as maximum values are respected. The resulting installed capacities per macro area are presented in the table 11 below:

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total
Wind	256.836	81.244	136.740	80.750	138.391	65.918	114.750	874.629
Solar [PV+CSP]	216.971	116.328	144.137	129.215	64.750	20.118		691.519
Biomass	49.750	20.000	42.000	19.750	42.750	9.750		184.000
Thermal	30.000	8.500	19.750	9.000	4.750	1.250		73.250

Table 12: Initial capacities for scenario quantification - X-7

In hourly simulations, this set of installed capacities results in an average of about **3800 hours of loss of load per year.** The main reason for adequacy problems is the lack of thermal units and hours winter days/weeks with high demand and only low generation of wind and solar. Furthermore the use rate of Biomass was lower than expected.

➔ These initial results have been used to run the semi-automatic optimization algorithm. Within this process capacities were re-allocated and increased to assure system adequacy and energy targets on macro area level for this scenario. As a binding constraint the imbalances of the macro areas were limited to the value assumed for the scenario - ±80%.

b) Macro area level: results after running the algorithm

The installed capacities at macro area level, before country quantification, are presented in figure 17 and the energy mixes as well as the balances of macro areas are shown in figure 18.

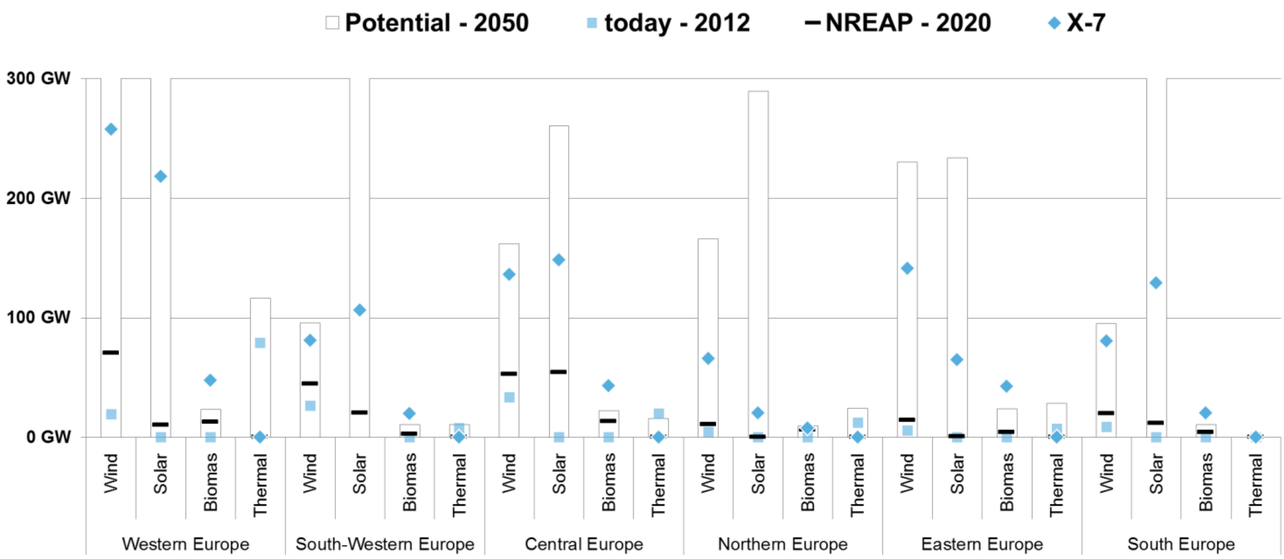

Figure 20: Intermediate installed capacities on step macro area – X-7

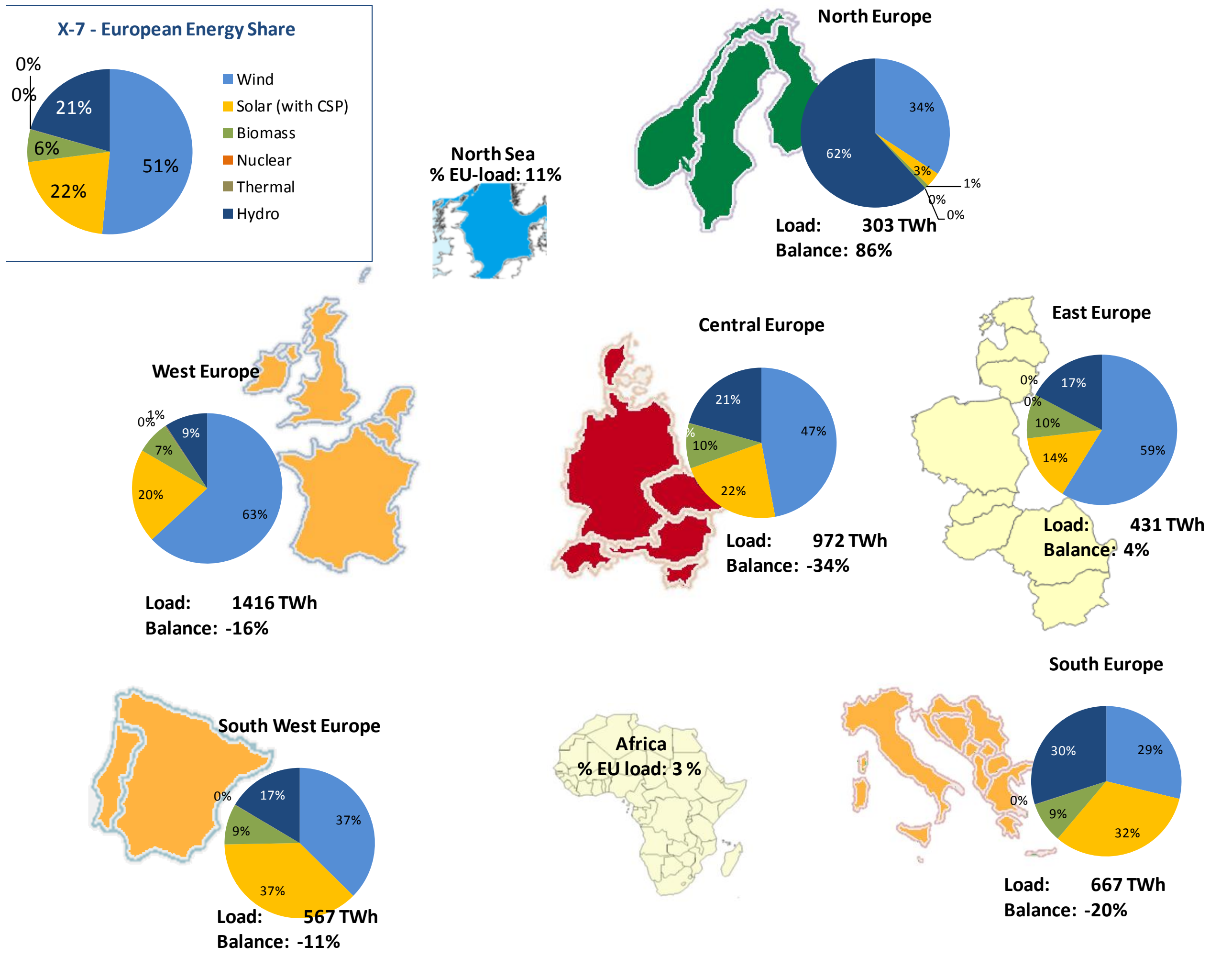

Figure 21: Intermediate energy mix on step macro area – X-7

The main conclusions at macro area level for whole Europe are:

- The share of Biomass is lower than expected, on the contrary solar share is higher.
- Continental Europe depends on Northern countries, which have a lot of wind and hydro production.
- In the Southern countries solar is the most important energy source.
- North Sea is an important source for energy.
- Peak units are required to ensure “Loss of Load” below limit – mainly during winter weeks with low wind and solar generation over a longer period.

Country level

a) Country level: results before consultation

The installed capacities, as obtained on macro area level, are distributed over the various countries within each macro area according to a set of scenario-dependant distribution keys.

Moreover, the 'thermal units' considered at macro area level are now split between OCGT, CCGT, coal and lignite fired power plants, based on the duration curve of use over one year and the CO_2 emission limitation of 70 Mt per year. At this moment, the demand side management optimisation is taken into account as well.

- ➔ These initial results are used to run the semi-automatic optimization algorithm. Within this process capacities are re-allocated and increased to assure system adequacy and energy targets on country level for this scenario. As a binding constraint the imbalances of the macro areas are limited to the value assumed for the scenario - ±80%.

In this scenario, 73 250 MW of peaking units are required to ensure adequacy. These units are used less than 100 hours per year in copper plate simulations. In this scenario, they could be biomass plants, demand side management or additional storage.

b) Country level: final results after consultation

The resulting set of installed capacities has been submitted to TSOS and stakeholders for consultation. Feedback has been included and a last Antares simulation has been run to re-check adequacy. The final results at country results are presented in the table 12 below:

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Peak – Units (MW)	Demand (GWh)	Balance (%)
AL	2.433	1.181	0	0	15.030	135,0%
AT	6.880	12.090	3.500	1.500	84.825	98,0%
BA	2.599	1.291	250	0	12.695	226,0%
BE	10.903	24.087	4.750	2.500	121.255	47,0%
BG	4.403	5.395	4.750	0	31.842	114,0%
CH	1.382	15.000	1.250	2.000	77.330	77,0%
CZ	10.234	13.048	5.000	1.750	71.763	67,0%

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Peak – Units (MW)	Demand (GWh)	Balance (%)
DE	98.326	98.599	27.750	13.000	665.705	57,0%
DK	18.708	2.038	3.750	1.000	42.667	146,0%
EE	8.141	803	1.000	250	12.488	160,0%
ES	69.383	102.523	17.250	8.500	498.020	86,0%
FI	29.531	5.835	3.750	1.250	82.580	125,0%
FR	124.197	106.905	28.250	16.000	649.447	86,0%
GR	25.851	15.068	3.750	0	67.841	170,0%
HR	6.254	3.782	0	0	23.924	104,0%
HU	4.897	13.997	7.250	0	59.428	80,0%
IE	13.628	3.836	250	2.000	43.086	107,0%
IT	41.290	101.044	14.750	9.000	431.389	76,0%
LT	15.163	1.343	1.750	500	28.047	135,0%
LU	739	1.030	0	250	7.383	45,0%
LV	13.811	1.133	1.750	500	20.980	179,0%
ME	520	490	0	0	3.220	381,0%
MK	371	1.374	0	0	8.438	92,0%
NL	14.997	22.247	4.000	3.000	160.723	47,0%
NO	12.175	5.364	500	0	102.015	242,0%
PL	81.918	24.220	14.250	3.000	172.220	112,0%
PT	11.861	13.805	2.750	0	70.943	112,0%
RO	4.828	10.980	9.250	0	68.262	111,0%
RS	1.431	4.986	1.000	0	31.392	83,0%
SE	24.211	8.919	5.500	0	131.557	125,0%
SI	472	2.332	750	250	14.940	92,0%
SK	5.230	6.880	2.750	500	26.539	98,0%

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Peak – Units (MW)	Demand (GWh)	Balance (%)
UK	93.112	59.896	12.500	6.500	439.063	97%

Table 13: Final installed capacities by technologies and balances on country level – X-7

The main conclusions from country level are:

- Generation of North Sea is an important source of energy for Germany, United-Kingdom, The Netherlands and Belgium, which have a generation deficit.
- The reduction of imbalances is difficult due to the reached potentials of wind and biomass in some countries.
- High power exchanges are required.
- Wind is the most important RES source.
- Amount of spilled energy is high (≈5,6 % of total generation).
- Peak units are required to assure SoS (ca. 73GW).

Cluster level

Based on distribution keys, installed capacities for each technology are distributed per clusters within each country. Potentials as maximum values are respected. Values on cluster level, after consultation, can be found in the Annex.

4.3.3. Conclusion and evaluation

Reaching the CO_2 emission target as well as the RES NREAP target is not a problem in this scenario. To achieve this scenario an increase of investments in RES is required. A high focus must be given to RES-technologies, which can provide flexibility in unit commitment like biomass and CSP.

To reach a 100% RES Scenario high difficulties have to be faced to ensure security of supply due to the high share of wind and solar. It can be achieved only through one of these solutions:

- Increase/development of long-term storage,
- Building peak units, which can be used during critical hours/weeks – fuel type could be biomass, other fossil fuel units,
- Increase demand side management,
- Install huge amounts of RES and acceptance of high spillage of energy.

4.4. Scenario X-10 - Big and market

4.4.1. General description

In this scenario, a global agreement for climate mitigation is achieved. Thus, CO_2 costs are high due to the existence of a global carbon market. Europe is fully committed to meet its 80-95% GHG reduction orientation by 2050 but it relies mainly on a market based strategy.

Moreover, in this scenario, there is a special interest on large scale centralized solutions, especially for RES deployment and storage. Public attitude towards deployment of RES technologies is indifferent in the EU, while acceptance of nuclear and shale gas, as energy sources, is positive since being preferred to decentralize local solutions. CCS technology is also assumed mature in this scenario.

Electrification of transport, heating and industry is considered to occur mainly at centralized (large scale) level. Only a minor shift towards 'greener' behaviours is experienced in this scenario compared to present practices. Therefore, the efficiency level is low. In general, the public is somehow passive, and the players are active in a market-driven energy system.

Expectations and guidelines on quantification process

Medium level of exchanges and rather balanced countries (imbalance < 30%) are expected in this scenario. The share of committable units is expected to be high enough to limit the problems of security of supply.

4.4.2. Quantification performance

European level

The targeted energy mix of the X-10 at European level is shown in the graph below. Among renewables, wind has the most important share as centralized RES are preferred in this scenario. European demand is 4337 TWh which, compared to other scenarios, is neither high (due to low level of new uses) nor low (due to low efficiency level).

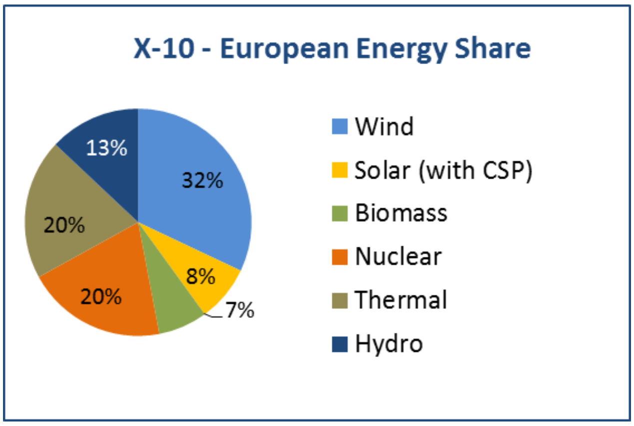

Figure 22: Detailed energy mix for quantification - X-10

Macro area

Macro area values presented below are those before country quantification and consultation.

a) Macro area level: initial results based on distribution keys

Based on distribution keys reflecting demand, capacity factors or expected levels of different technologies, energy mix and corresponding installed capacities are distributed per macro Areas. At the same time, potentials as maximum values are respected. The resulting installed capacities per macro area are presented in the table 13 below:

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total
Wind	162.284	52.530	95.744	42.040	57.438	26.266	71.400	507.702
Solar [PV+CSP]	60.877	65.353	76.103	62.049	22.502	3.399		290.283
Biomass	17.500	6.000	16.000	9.250	8.000	6.500		63.250
Nuclear	68.800	8.000	9.000	0	19.200	11.200		116.200
Thermal	84.850	36.050	73.350	66.900	27.800	9.150		298.100

Table 14: Initial capacities for scenario quantification - X-10

In hourly simulations, this set of installed capacities results in an average of **2700 hours of loss of load per year.** The main reason for adequacy problems is the lack of thermal units. At first, a use rate of 80% was assumed for thermal units to calculate the installed capacities. In hourly simulations, the real use rate is much lower resulting in lack of power in some hours and fossil annual generation lower than expected.

➔ These initial results have been used to run the semi-automatic optimization algorithm. Within this process capacities were re-allocated and increased to assure system adequacy and energy targets on macro area level for this scenario. As a binding constraint the imbalances of the macro areas were limited to the value assumed for the scenario - ±30%.

b) Macro area level: results after running the algorithm

The installed capacities at macro area level, before country quantification, are presented in figure 20 and the energy mixes as well as the balances of macro areas are shown in figure 23.

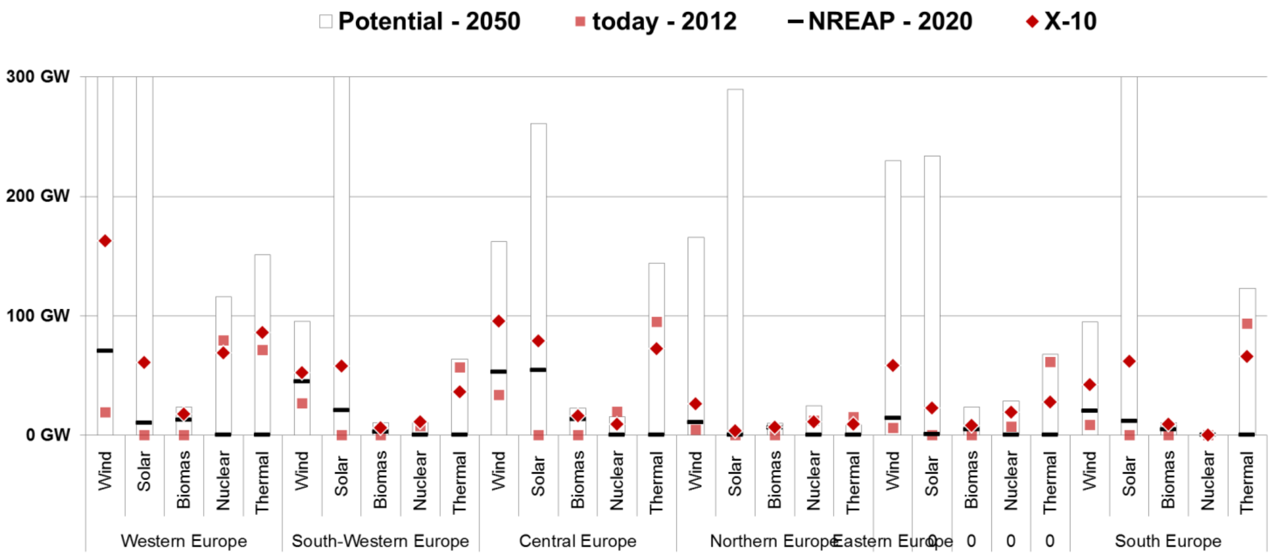

Figure 23: Intermediate installed capacities on step macro area – X-10

The European and macro area energy mixes are in the graph below with the macro area loads and balances.

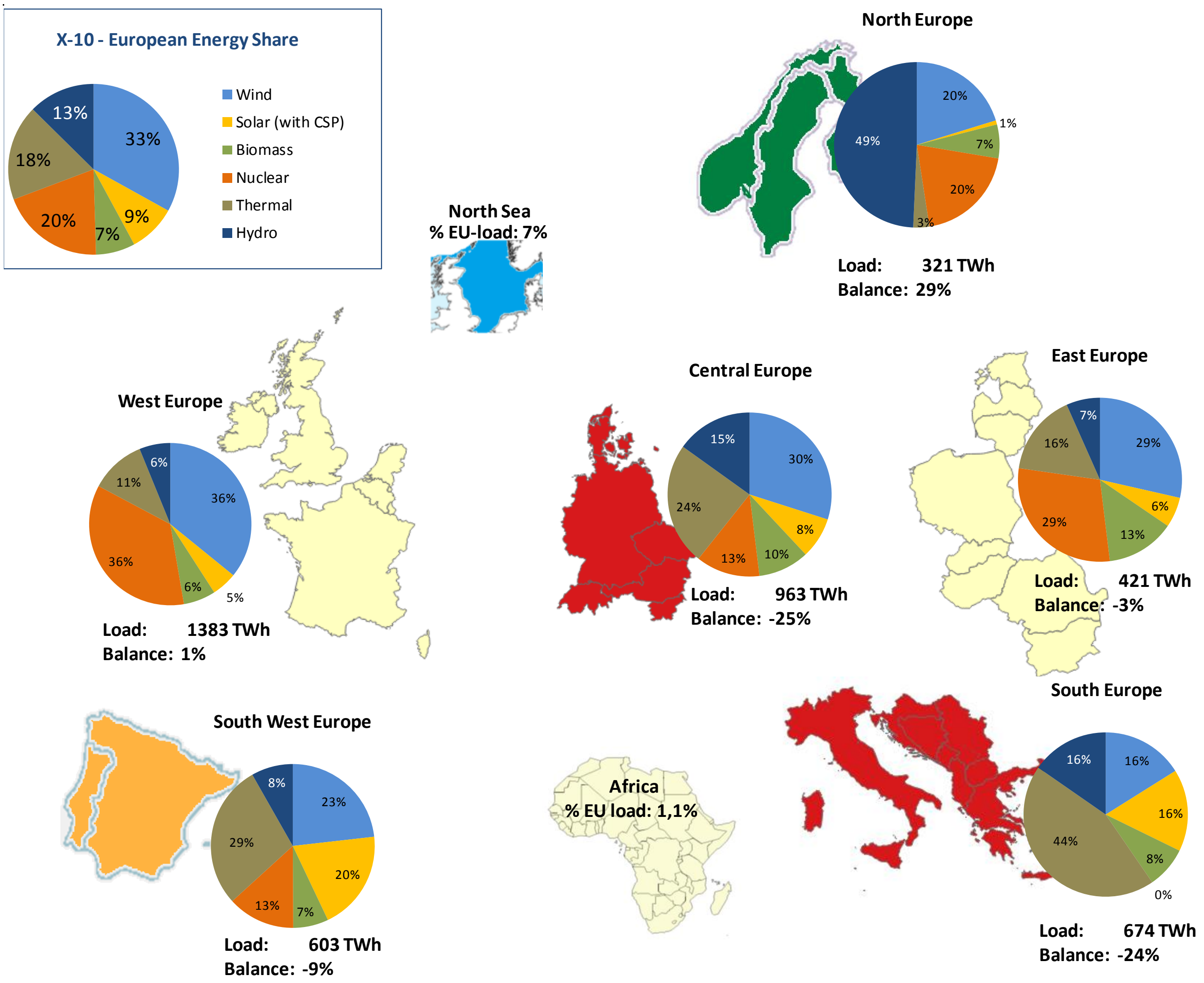

Figure 24: Intermediate energy mix on step macro area – X-10

The main conclusions at macro area level for whole Europe are:

- European energy mix for X-10 is respected.
- Thermal capacity must be decreased by a factor 1.7 (minus 180GW) compared to today.
- Overall nuclear capacity should remain unchanged when compared to today, but its localisation is changed due to phase out in some countries.
- Wind capacity must be increased by a factor of 2.4 compared to NREAPS 2020.
- PV capacity must be increased by a factor of 2.7 compared to NREAPS 2020.
- CSP capacity must be increased by a factor of 2.7 compared to NREAPS 2020.

Country level

a) Country level: results before consultation

The installed capacities, as obtained on macro area level, are distributed over the various countries within each macro area according to a set of scenario-dependant distribution keys.

Moreover, the 'thermal units' considered at macro area level are now split between OCGT, CCGT, coal and lignite fired power plants, based on the duration curve of use over one year and the CO_2 emission limitation of 70 Mt per year. At this moment, the demand side management optimization is taken into account as well.

➔ These initial results are used to run the semi-automatic optimization algorithm. Within this process capacities are re-allocated and increased to assure system adequacy and energy targets on country level for this scenario. As a binding constraint the imbalances of the macro areas are limited to the value assumed for the scenario - ±30%.

In this scenario, 55 000 MW of peaking units (OCGT) are required to ensure adequacy. These units are used less than 100 hours per year in copper plate simulations.

b) Country level: final results after consultation

The resulting set of installed capacities has been submitted to TSOS and stakeholders for consultation. Feedback has been included and a last Antares simulation has been run to re-check adequacy. The final results at country results are presented in the table 14 below:

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (GWh)	Balance (%)
AL	478	1.000	0	0	1.500	15.030	84,0%
AT	5.751	7.040	1.250	0	3.500	84.023	92,0%
BA	767	1.775	0	0	1.300	12.996	113,0%
BE	6.899	5.182	2.500	0	21.250	121.165	71,0%
BG	1.811	3.723	750	1.600	3.050	33.660	110,0%
CH	1.382	9.825	1.500	0	5.250	77.318	92,0%
CZ	6.155	4.072	1.000	8.000	500	70.698	116,0%
DE	70.844	51.753	9.000	0	62.100	660.937	64,0%

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (GWh)	Balance (%)
DK	10.951	1.591	3.000	0	500	39.080	108,0%
EE	5.412	538	250	0	500	12.367	122,0%
ES	44.351	57.798	5.000	8.000	30.050	529.401	79,0%
FI	10.859	569	3.000	3.200	8.150	83.528	109,0%
FR	57.780	40.366	7.750	48.000	17.050	657.057	104,0%
GR	15.565	10.352	1.000	0	3.000	67.315	108,0%
HR	1.822	1.299	0	0	2.550	23.584	77,0%
HU	3.481	3.787	1.250	3.200	4.000	59.548	91,0%
IE	12.303	558	250	0	1.750	41.871	104,0%
IT	22.348	44.729	8.000	0	52.350	435.969	81,0%
LT	7.474	902	500	1.600	3.250	29.594	137,0%
LU	280	171	0	0	1.000	7.591	57,0%
LV	6.848	699	500	0	1.750	21.769	122,0%
ME	106	458	0	0	500	3.380	73,0%
MK	196	617	0	0	1.800	8.839	112,0%
NL	12.198	5.362	2.750	0	29.950	170.422	66,0%
NO	6.261	1.303	750	0	0	111.578	139,0%
PL	27.180	5.386	2.750	8.000	6.150	159.877	92,0%
PT	8.179	7.555	1.000	0	6.000	75.353	103,0%
RO	4.000	6.159	1.500	3.200	7.350	63.961	124,0%
RS	757	1.819	250	0	3.900	32.390	105,0%
SE	9.146	1.527	2.750	8.000	1.000	139.275	116,0%
SI	382	1.651	250	1.000	500	14.373	111,0%
SK	1.232	1.308	500	1.600	1.750	28.190	95,0%
UK	73.105	9.409	4.250	20.800	14.850	388.699	118%

Table 15: Installed capacities by technologies and balances on country level – X-10

NB: Imbalance in Germany is still higher than 30%; however, no offshore wind is included for this country as it is part of North Sea. As a result, the level of imbalance if offshore wind was included would be below 30%

The main conclusions from country level are:

- Countries with a high wind potential and/or no nuclear phase out tend to be exporters: Ireland, United-Kingdom, France, Czech Republic, Slovenia, Romania, Bulgaria, Lithuania, Sweden.
- Italy, Germany and Switzerland are the countries with the most critical imbalances.
- Before taking into account the NREAPS 2020, the distribution keys of PV in Germany lead to a significant lower value.
- Nuclear had to be slightly reduced in Central Europe as it was only installed in Slovenia and Czech republic.

<u>Cluster level</u>

Based on distribution keys, installed capacities for each technology are distributed per clusters within each country. Potentials as maximum values are respected. Values on cluster level, after consultation, can be found in the annex.

4.4.3. Conclusion and evaluation

In scenario X-10 CCS-technology plays an important role to meet the CO_2-emission targets. The annual emission of CO_2 resulting from hourly simulations is 43Mt which is slightly better than EC target (70Mt) but 270 Mt of CO_2 need to be stored annually. A potential of 117Gt of CO_2 storage is then sufficient for more than 400 years. Out of 297GW of thermal plants, in this scenario, 113 GW are gas with CCS, 25GW hard coal with CCS and 13GW lignite with CCS.

To attain the high RES shares, NREAPS 2020 are not sufficient. Wind installed capacity is quite high: 500 GW including 76 GW from North Sea. It requires a lot of investment compared to 2020 targets (installed capacity should be more than doubled). PV plays a less significant role (275 GW) but the need for investment is also high: the capacity is more than twice the 2020 targets.

In scenario X-10, the European installed capacity of nuclear is similar to today level. However, the installed capacities per country have to be increased in the countries without nuclear phase out to mitigate the phase out in Germany, Belgium and Switzerland.

4.5. Scenario X-13 - Large fossil fuel with CCS and nuclear

4.5.1. General description

In this Scenario, a global agreement for climate mitigation is achieved and Europe is fully committed to its target of 80-95% GHG reduction. Thus, CO_2 costs are high due to the existence of a global carbon market.

Europe is mainly following a non-RES strategy to reach this target. Acceptance of nuclear and shale gas as energy sources is positive. Nuclear and fossil fuel plants with CSS play pivotal roles in achieving the 80-95% GHG targets without large scale RES deployment. Public attitude towards deployment of RES technologies is indifferent in the EU. There is a low focus on development of RES and storage solutions.

Electrification of transport, heating and industry is considered to occur mainly at centralized (large scale) level. Energy efficient options (including DSM and flexibility of EV use) are deployed only at medium level, mainly aiming at reducing energy demand. Indeed a minor shift towards 'greener' behaviours is experienced in this Future compared to present practices.

No further flexibility is needed since variable generation from PV and wind is low.

The energy strategy is deployed from a top-down approach at EU level with coordinated trans-national approaches based on a strong framework for policy and incentives, supporting market operation. In general, the public is somehow passive and everything has to be coordinated at high level, following a top-down vision. In this case, Electricity exchanges with outside Europe are low.

Europe is mainly relying on the non-RES technologies. Fossil fuel plants with CCS and nuclear play fundamental roles in the energy mix.

Expectations and guidelines on quantification process

Ex ante expectations for the quantification process were high international exchanges and minor imbalances (i.e. below 30%). Furthermore, no significant problems with security of supply are expected.

4.5.2. Quantification performance

European level

The targeted energy mix of the X-13 scenario at European level is shown in the graph below. Thermal and nuclear have the highest share in the energy mix. Among renewables, wind has the most important share as centralized RES are preferred in this scenario. European demand is 4.854 TWh which is rather high compared to other scenarios. Only X-5 has a higher demand.

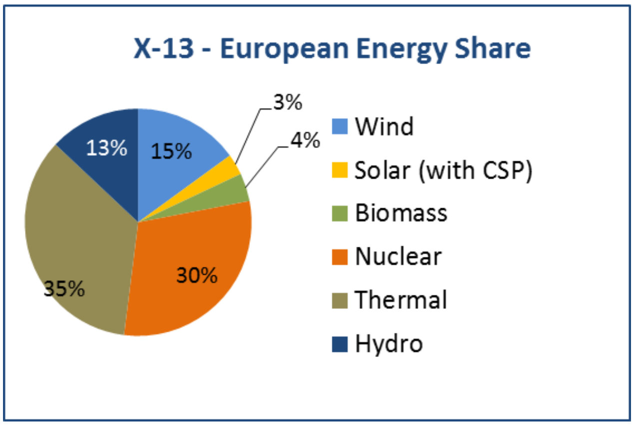

Figure 25: Detailed energy mix for quantification - X-13

<u>Macro area</u>

Macro area values presented below are those before country quantification and consultation.

a) Macro area level: initial results based on distribution keys

Based on distribution keys reflecting demand, capacity factors or expected levels of different technologies, energy mix and corresponding installed capacities are distributed per macro areas. At the same time, potentials as maximum values are respected. The resulting installed capacities per macro area are presented in the table 15 below:

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total
Wind	85.365	44.875	61.058	24.477	32.575	13.439	39.100	300.889
Solar [PV+CSP]	22.782	46.967	70.929	37.137	10.950	6.256		195.021
Biomass	15.500	4.500	14.500	5.500	5.750	6.750		52.500
Nuclear	110.400	8.000	9.000	0	27.200	14.400		169.000
Thermal	117.200	55.400	103.500	84.600	32.300	8.000		401.000

Table 16: Initial capacities for scenario quantification - X-13

In hourly simulations, this set of installed capacities results in an average of **3.307 hours of loss of load per year.** The main reason for adequacy problems is the lack of thermal units. At first, a use rate of 80% was assumed for thermal units to calculate the installed capacities. In hourly simulations, the real use rate is much lower resulting in lack of power in some hours and fossil annual generation lower than expected.

➔ These initial results have been used to run the semi-automatic optimization algorithm. Within this process capacities were re-allocated and increased to assure system adequacy and energy targets on macro area level for this scenario. As a binding constraint the imbalances of the macro areas were limited to the value assumed for the scenario - ±30%.

b) Macro area level: results after running the algorithm

The installed capacities at macro area level, before country quantification, are presented in figure 23 and the energy mixes as well as the balances of macro areas are shown in figure 24.

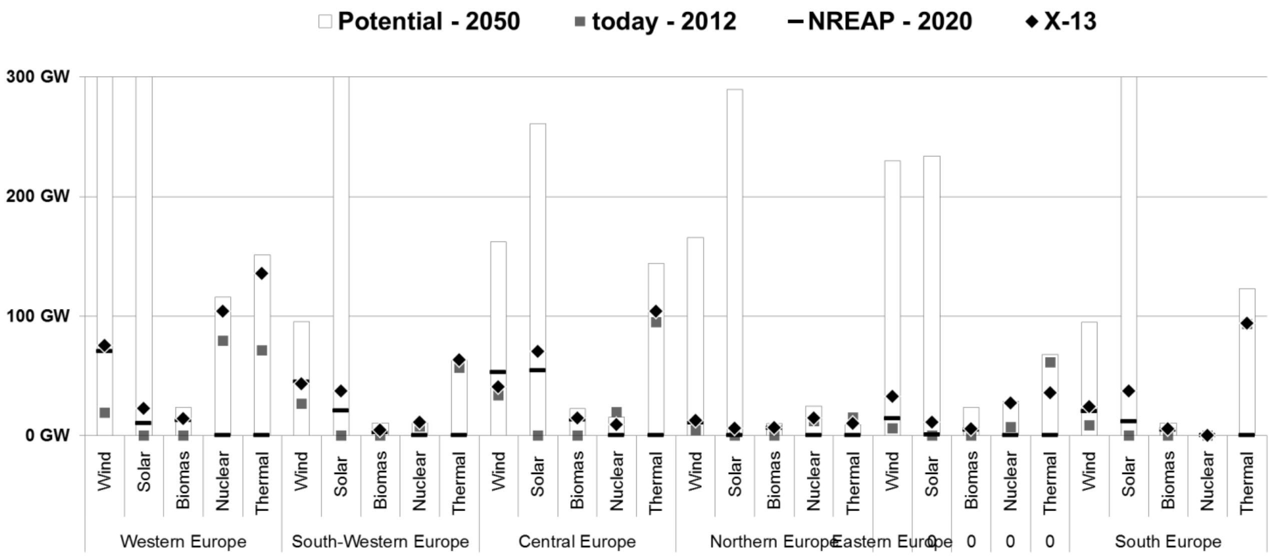

Figure 26: Intermediate installed capacities on step macro area – X-13

The European and macro area energy mixes are in the graph below with the macro area loads and balances.

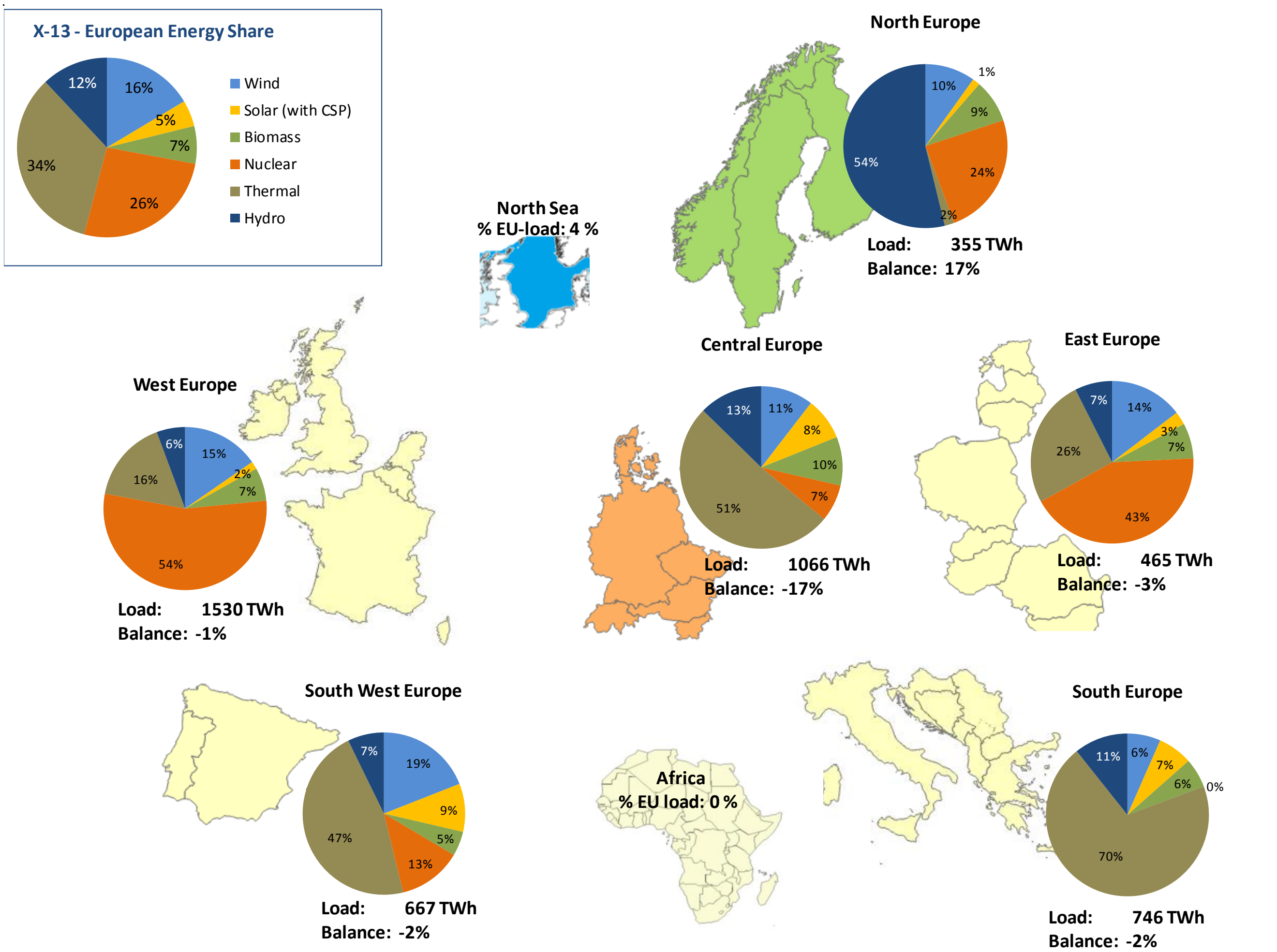

Figure 27: Intermediate energy mix on step macro area – X-13

The main conclusions at macro area level for whole Europe are:

- European energy mix for X-13 is not respected because of lack of nuclear potential. The share of nuclear is 6% lower than initially proposed. This is due to the nuclear phase out in several countries.
- Thermal remains stable compared to today.
- Nuclear must be increased of 40 GW or factor 1.3 compared to today.
- Wind capacity must be increased by a factor of 2.1 compared to NREAPS 2020.
- PV capacity must be increased by a factor of 1.7 compared to NREAPS 2020.
- Biomass must remain stable compared to NREAPS 2020.

<u>Country level</u>

a) Country level: results before consultation

The installed capacities, as obtained on macro area level, are distributed over the various countries within each macro area according to a set of scenario-dependant distribution keys.

Moreover, the ‘thermal units’ considered at macro area level are now split between OCGT, CCGT, coal and lignite fired power plants, based on the duration curve of use over one year and the CO_2 emission limitation of 70 Mt per year. At this moment, the demand side management optimization is taken into account as well.

➔ These initial results are used to run the semi-automatic optimisation algorithm. Within this process capacities are re-allocated and increased to assure system adequacy and energy targets on country level for this scenario. As a binding constraint the imbalances of the macro areas are limited to the value assumed for the scenario - ±30%.

In this scenario, 61 000 MW of peaking units (OCGT) are required to ensure adequacy. These units are used less than 100 hours per year in copper plate simulations.

b) Country level: final results after consultation

The resulting set of installed capacities has been submitted to TSOS and stakeholders for consultation. Feedback has been included and a last Antares simulation has been run to re-check adequacy. The final results at country results are presented in the table 16 below:

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (MW)	Balance (MW)
AL	224	368	0	0	1.000	15.030	79,0%
AT	2.985	7.327	1.250	0	5.800	88.317	86,0%
BA	345	587	0	0	1.300	14.379	89,0%
BE	4.320	4.045	2.500	0	21.500	134.061	85,0%
BG	1.440	679	500	3.200	1.800	37.242	113,0%
CH	627	6.449	1.250	0	7.000	74.854	105,0%
CZ	2.547	2.550	500	8.000	6.700	78.223	123,0%
DE	45.749	51.753	8.250	0	80.700	731.280	71,0%
DK	8.908	1.646	3.000	0	2.300	43.240	125,0%
EE	3.009	290	250	0	1.000	13.683	79,0%

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Demand (MW)	Balance (MW)
ES	38.000	40.967	4.000	8.000	46.900	585.745	85,0%
FI	3.861	954	3.000	6.400	6.500	92.417	114,0%
FR	22.397	9.976	8.000	83.200	17.600	726.987	117,0%
GR	7.604	3.306	750	0	9.000	74.479	110,0%
HR	842	2.728	0	0	3.300	26.094	82,0%
HU	1.530	2.133	750	6.400	4.500	65.886	115,0%
IE	8.223	224	250	0	5.500	46.328	100,0%
IT	15.028	28.310	4.500	0	64.800	482.369	85,0%
LT	4.050	433	250	1.600	3.000	32.744	103,0%
LU	131	113	0	0	500	8.399	54,0%
LV	3.717	341	250	0	2.000	24.086	89,0%
ME	46	458	0	0	800	3.740	215,0%
MK	110	357	0	0	1.800	9.779	99,0%
NL	11.178	1.560	1.000	0	31.100	188.560	77,0%
NO	5.031	2.489	750	0	0	123.454	131,0%
PL	14.344	2.787	2.500	9.600	10.800	176.893	92,0%
PT	6.875	6.000	500	0	8.500	83.373	90,0%
RO	4.000	3.577	1.000	3.200	7.700	70.768	118,0%
RS	279	1.022	250	0	2.600	35.837	76,0%
SE	4.547	2.813	3.000	8.000	1.500	140.089	112,0%
SI	111	1.091	250	1.000	500	15.903	109,0%
SK	486	711	250	3.200	1.500	31.190	116,0%
UK	39.247	6.977	3.750	27.200	41.500	430.068	115%

Table 17: Final installed capacities by technologies and balances on country level – X-13

The main conclusions from country level are:

- Except for Lithuania, Poland and Spain, all countries with nuclear installed capacity tend to be net exporters.
- France has almost half of all installed capacity of nuclear in Europe.
- Nuclear had to be reduced in Central Europe as it was only installed in Slovenia and Czech Republic.
- Italy and Switzerland were the countries with the most critical imbalances but this was solved with an increase in thermal.
- For almost all countries modifications were done to reach NREAPS 2020.

Cluster level

Based on distribution keys, installed capacities for each technology are distributed per clusters within each country. Potentials as maximum values are respected. Values on cluster level, after consultation, can be found in the Annex.

4.5.3. Conclusion and evaluation

Despite the nuclear phase out in Belgium, Germany and Switzerland, the European installed capacity of nuclear will increase by factor 1.5 compared to todays' situation. Thermal will slightly decrease and has the highest share (i.e. 36%) in the total European production.

Carbon capture storage is needed in this scenario to achieve the EC target of CO_2 reduction: 70% of all thermal plants have CCS. Due to the availability of this technology the 95% reduction target (70 Mt CO_2/year) can be met (annual emissions are around 60Mt) but 580 Mt of CO_2 need to be stored annually. A potential of 117Gt of CO_2 storage is then sufficient for 190 years

Concerning renewables, wind, solar and biomass will increase with factor 1.3, 2 and 1.1 compared to NREAP values.

4.6. Scenario X-16 - Small and local

4.6.1. General description

In this Scenario, the global community has not succeeded in reaching an agreement for climate mitigation. Yet, Europe is fully committed to meet its target of 80-95% GHG reduction. Compared to the other scenarios, the European member states have chosen a bottom-up strategy mainly based on small-scale/local solutions to reach this target.

Common agreements/rules for transnational initiatives regarding the operation of an internal EU market, EU wide security of supply and coordinated use of interconnectors for transnational energy exchanges do not exist. The focus is rather on local solutions dealing with de-centralized generation and storage and smart grid solutions at transmission and mainly on a distribution level.

In this Scenario, there is a high focus on deployment of de-centralized storage and RES solutions (including CHP and Biomass), while nuclear and CCS are not considered as options to reach the GHG emission reduction target. The public attitude towards the deployment of local de-centralized RES technologies is positive in the EU.

A high degree of electrification of transport, heating and industry is considered to occur mainly at de-centralized (small scale) level; there is a corresponding high focus on the deployment of energy efficient solutions (including DSM and flexibility of EV use).

GDP growth in EU is assumed low, mainly due an inhomogeneous economic activity landscape among Member States. Demographic change towards 2050 is assumed to be migration only at EU level.

A major shift towards 'greener' behaviours is experienced in this scenario compared to present practices. In general, the public is very active and most of the development occurs at a local de-centralized level.

The European permitting framework (including nature legislation) is also inhomogeneous/de-centralized at member state level. Some countries will still require energy imports from outside the EU.

In this scenario, focus is on de-centralized RES. 60% of the demand is covered mostly by decentralized RES, while centralized RES fulfil 25% of the demand. Fossil fuel-fired power plants and nuclear power plants cover 5%, respectively 10% of the demand. X-16 is the scenario with the lowest annual demand (3.159 TWh per year) amongst the scenarios considered in the e-Highway 2050 project.

Expectations and guidelines on quantification process

Low imbalances are expected between the countries. During the quantification, the limit is to a 10% deficit or surplus of generation compared to the demand in a macro area or country. Security of supply problems may persist (due to the high share of RES).

4.6.2. Quantification performance

European level

Given the scenario description, the energy shares are distributed over the range of technologies considered using the distribution keys defined for this scenario. Assuming fixed capacity factors for each technology, these generation shares were translated to installed capacities.

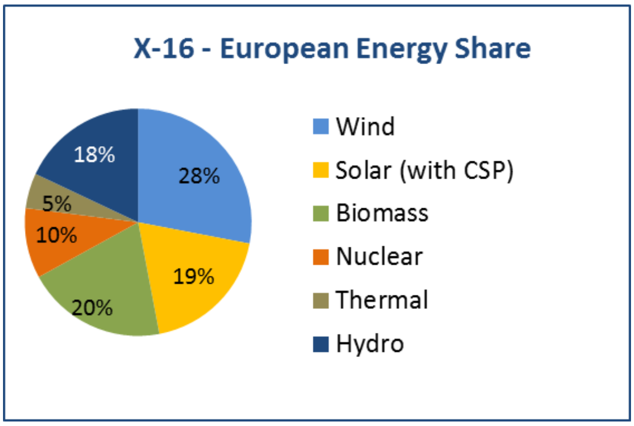

Figure 28: Detailed energy mix for quantification - X-16

Macro area

Macro area values presented below are those before country quantification and consultation

a) *Macro area level: initial results based on distribution keys*

Based on distribution keys reflecting demand, capacity factors or expected levels of different technologies, energy mix and corresponding installed capacities are distributed per macro Areas. At the same time, potentials as maximum values are respected. The resulting installed capacities per macro area are presented in the table 17 below:

Capacity (MW)	West Europe	Iberian Peninsula	Central Europe	South Europe	East Europe	Nord Europe	North Sea	Total
Wind	124.743	46.016	98.276	53.793	37.197	12.848	11.050	383.923
Solar [PV+CSP]	177.142	96.398	135.473	131.547	39.109	4.232		583.901
Biomass	33.000	11.250	23.000	11.250	20.250	9.000		107.750
Nuclear	27.200	3.200	4.800	0	6.400	6.400		48.000
Thermal	45.000	19.000	26.350	22.050	14.000	250		126.650

Table 18: Initial capacities for scenario quantification - X-16

In hourly simulations, this set of installed capacities results in an average of **2560 of loss of load per year**

- ➔ These initial results have been used to run the semi-automatic optimization algorithm. Within this process capacities were re-allocated and increased to assure system adequacy and energy targets on macro area level for this scenario. As a binding constraint the imbalances of the macro areas were limited to the value assumed for the scenario - ±10%.

b) Macro area level : results after running the algorithm

The installed capacities at macro area level, before country quantification, are presented in figure 26 and the energy mixes as well as the balances of macro areas are shown in figure 29.

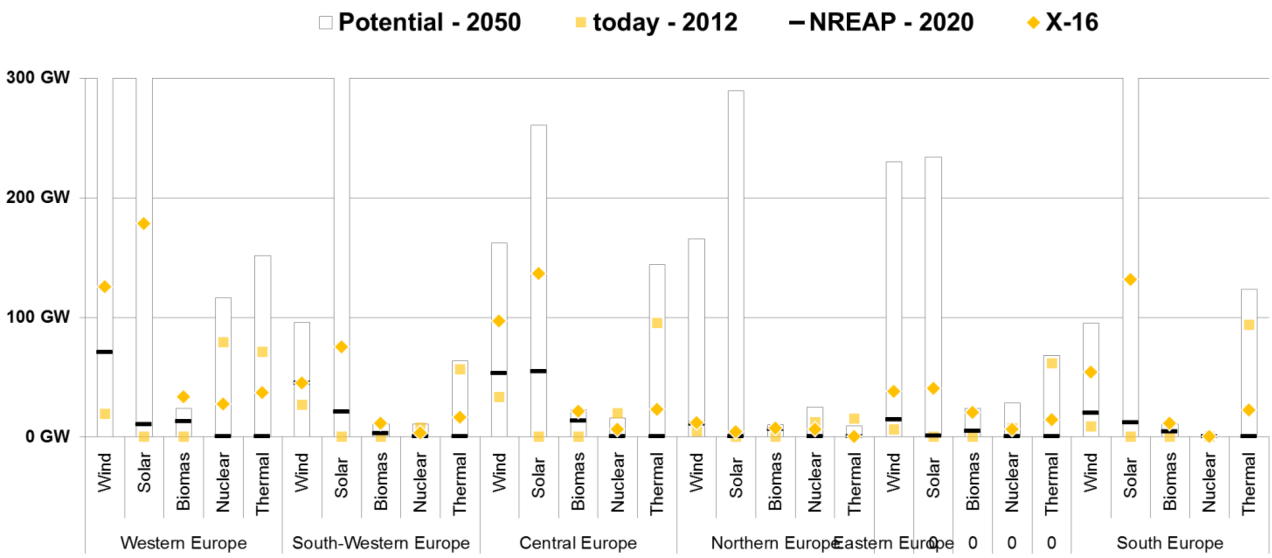

Figure 29: Intermediate installed capacities on step macro area – X-16

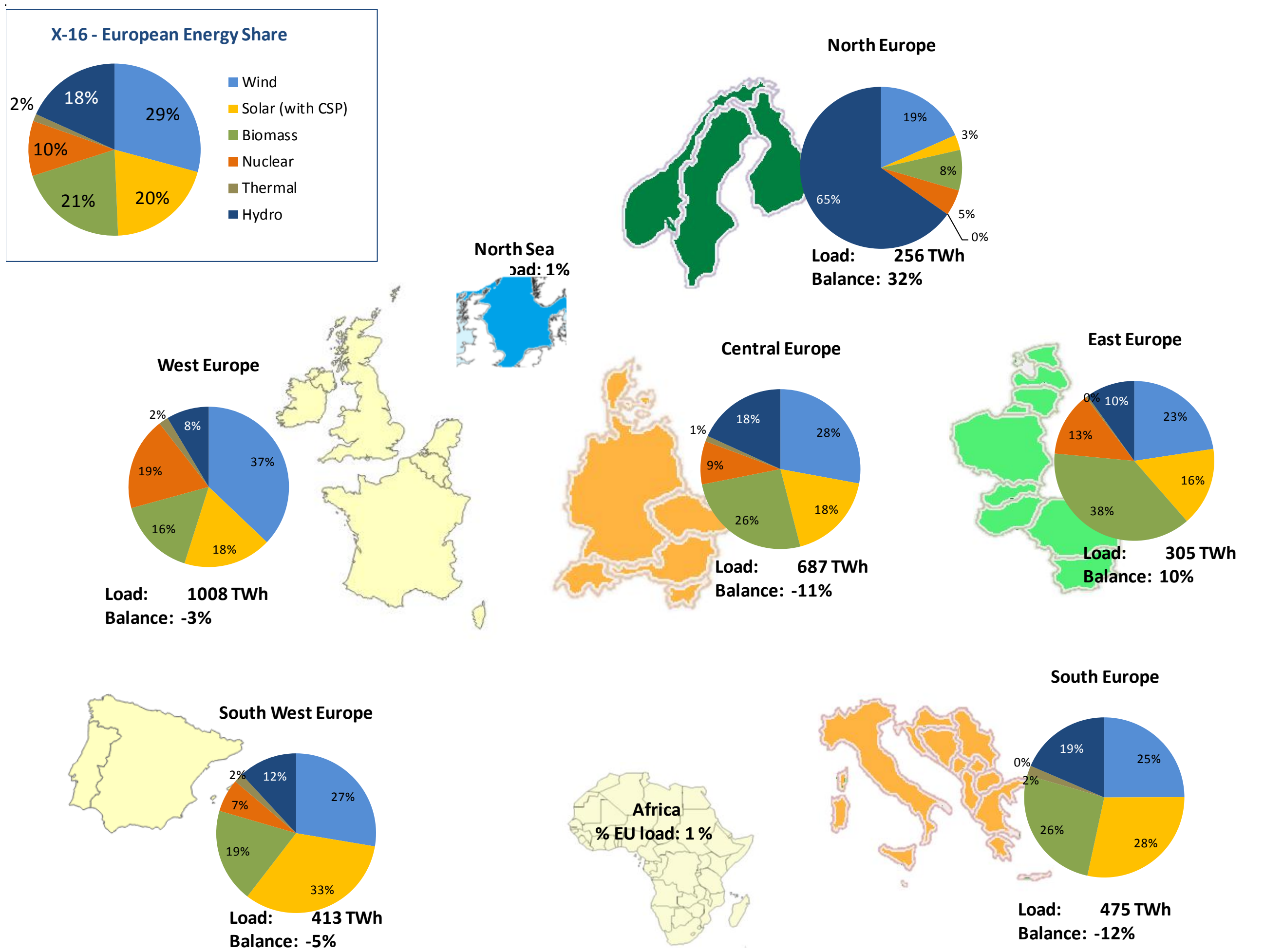

Figure 30: Intermediate energy mix on step macro area – X-16

The main conclusions from macro area level are:

- The annual imbalances in Europe in this scenario are low. Only North Europe has a high surplus, due to the low demand and the availability of hydro power in the North.
- West Europe and South West Europe are mostly self-sufficient, while North and East Europe export energy.
- The energy mix in Eastern Europe is dominated by biomass and nuclear power.
- West Europe is characterized by high shares of wind and nuclear power.
- South-West Europe is characterized by high wind and solar power.
- Central and South Europe have a well-balance energy mix, but both import energy from other regions.

In terms of installed capacity:

- The thermal and nuclear capacity should be drastically reduced compared to today's levels.

Country	Wind	Solar [PV + CSP]	Biomass	Nuclear	Thermal	Demand	Balance
AL	529	2.351	0	0	1.000	15.030	71%
AT	2.578	2.827	1.250	0	1.000	60.170	97%
BA	1.121	1.016	0	0	750	9.979	99%
BE	10.915	21.052	6.500	0	6.500	87.794	102%
BG	2.771	3.805	2.250	0	0	26.193	97%
CH	1.381	15.000	1.500	0	250	60.274	106%
CZ	3.147	4.469	1.750	4.800	5.000	52.818	113%
DE	85.419	109.275	15.000	0	17.600	466.152	89%
DK	4.928	69	2.500	0	1.000	28.656	97%
EE	2.063	1.449	500	0	1.000	9.113	101%
ES	39.141	87.300	9.750	3.200	16.000	363.178	100%
FI	2.500	10	3.000	6.400	250	66.059	112%
FR	53.678	77.098	16.000	14.400	10.500	479.001	100%
GR	9.085	8.414	2.250	0	7.000	50.684	121%
HR	2.042	4.085	250	0	500	16.880	98%
HU	4.534	3.979	4.000	1.600	3.500	42.354	110%
IE	6.635	4.080	500	0	4.000	28.392	107%
IT	39.031	108.833	7.750	0	8.500	364.255	94%
LT	3.267	2.959	750	1.600	1.000	22.250	114%
LU	540	904	500	0	1.000	5.362	107%
LV	2.910	3.071	1.250	0	2.500	16.108	121%
ME	183	388	0	0	0	2.562	95%
MK	372	2.438	250	0	500	6.576	111%

NL	14.531	31.565	4.500	1.600	7.000	117.963	98%
NO	3.535	0	500	0	0	91.514	162%
PL	14.798	19.561	7.000	1.600	2.500	114.220	86%
PT	6.875	9.098	1.500	0	3.000	51.027	114%
RO	4.737	1.022	3.000	1.600	3.000	45.627	118%
RS	1.430	4.021	750	0	3.800	24.986	98%
SE	6.813	4.222	5.500	0	0	109.416	107%
SI	283	2.928	500	0	500	10.914	111%
SK	2.118	3.263	1.500	0	500	20.353	92%
UK	38.985	43.347	5.500	11.200	17.000	321.117	95%

- The wind and solar capacity must be significantly higher than those foreseen in the NREAPS 2020: twice higher for wind and 5.2 times for solar.
- In none of the regions the potentials are reached, expect for biomass (potential reached in all regions except Central Europe).

Country level

a) Country level: results before consultation

The installed capacities, as obtained on macro area level, are distributed over the various countries within each macro area according to a set of scenario-dependant distribution keys.

Moreover, the ‘thermal units’ considered at macro area level are now split between OCGT, CCGT, coal and lignite fired power plants, based on the duration curve of use over one year and the CO_2 emission limitation of 70 Mt per year. At this moment, the demand side management optimisation is taken into account as well.

➔ These initial results are used to run the semi-automatic optimization algorithm. Within this process capacities are re-allocated and increased to assure system adequacy and energy targets on country level for this scenario. As a binding constraint the imbalances of the macro areas are limited to the value assumed for the scenario - ±10%.

In this scenario, 20 750 MW of peaking units (OCGT) are required to ensure adequacy. These units are used less than 100 hours per year in copper plate simulations.

b) Country level: final results after consultation

The resulting set of installed capacities has been submitted to TSOS and stakeholders for consultation. Feedback has been included and a last Antares simulation has been run to re-check adequacy. The final results at country results are presented in the table 18 below:

Table 19: Final installed capacities by technologies and balances on country level – X-16

After country level, the energy mix is slightly different from the energy mix targeted in this scenario: solar power is more explicitly present in the energy mix (22% versus 19%) at the expense of thermal generation (2% versus 5%).

<u>Cluster level</u>

Based on distribution keys, installed capacities for each technology are distributed per clusters within each country. Potentials as maximum values are respected. Values on cluster level, after consultation, can be found in the annex.

4.6.3. Conclusion and evaluation

In scenario X-16, the demand is considerably lower than in other scenarios. Focus should be on energy efficiency if this scenario is to be reached. As a result of the high share of RES and low demand, CO_2 emissions are well below the 70 Mt/year target (consistent with a 95% decrease compared to 1990 levels): CO_2 emissions are expected to amount to 48 Mt CO_2 per year. To ensure the reliability of the system, a significant amount of biomass and gas-fired units is needed.

To attain the high RES shares, NREAPS 2020 are not sufficient. Increased investments, especially in PV, will be needed.

To ensure reliability, biomass (twice the value foreseen in the NREAPs 2020) and gas-fired units will have important role although the latter will have very few running hours per year. Compared to today's values however, this scenario means a significant decommissioning of thermal and nuclear units throughout Europe. In 2050, only 120 GW of thermal units and 50 GW of nuclear units remain – just slightly above the installed capacity in Germany (incl. RES) today.

In this scenario, RES (including hydro) covers 88% of the demand. Wind and PV are the main RES, closely followed by biomass and hydro. To achieve this energy mix, minor exchanges within Europe would be needed. In general, generation/demand imbalances are limited to +/- 12%. Only for some countries in the North of Europe (e.g. Norway), the abundant availability of hydro power and the low demand triggers a rather high export (generation exceeds demand by 45%) to Central, West and South Europe.

5. Outlook and further steps

The Deliverable 2.1 describes the work that has been performed in Task 2.1 to compute installed capacities per cluster level for the different scenarios. Based on the verbal scenario description from working package 1 and the European Cluster model from task 2.2 a three step methodology has been implemented to receive this information. After an assessment of the demand situation in 2050 in the particular scenarios, hourly demand series have been deducted. Afterwards a three step approach was pursued, that defined installed capacities per technologies first on macro area scale, than on country-level and finally for each of the European clusters. During this process system adequacy was considered (except for step 3 on cluster-level) to have a sufficient level of security of supply in the year 2050. The final results elaborated in task 2.1 have been put for consultation among stakeholders and the received feedback has been used to improve the final results.

For the next steps in working package 2, the identified installed capacities are "fixed" – meaning, that any changes made to the electrical system are now done by developing the overlay transmission grid. The starting point is an equivalent cluster model of the existing transmission system, including the grid reinforcements already planned for the next decade that has been developed in task 2.2. This whole picture is provided by the Ten Year Network Development Plan (TYNDP). Links between the clusters are transmission equivalents, enabling scheduled unit commitment optimization and grid analysis. Each of these transmission equivalents is characterized by its thermal capacity and impedance, latter describing the load flow distribution within the network.

Based on this representation, the system simulations are then performed. On an hourly basis unit commitment & generation dispatching are optimized (minimization of costs) for different Monte-Carlo years and for the different scenarios in 2050. This "market" optimization thus takes into account grid characteristics. Therefore, a realistic use of the transmission is taken into account in order to identify the weaknesses and the constraints in the existing transmission system. The identification of the possible transmission corridors is performed by assessing the benefit for the overall generation costs of the power system. To consider mutual influences a step-wise re-calculation of the transmission capacities and impedances is done to consider the effects of new transmission lines. This iterative process is repeated until the system in 2050 is free of grid constraints or until a further grid development promises a negative benefit (see the figure 31).

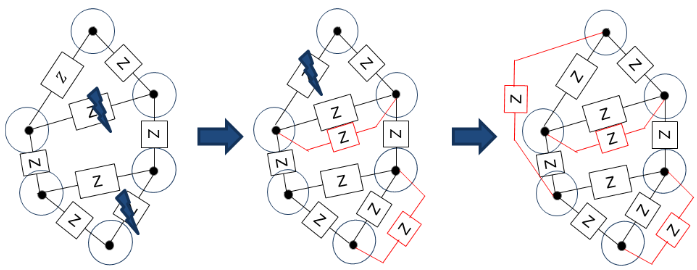

Figure 31: Iterative development until constraints have been resolved

The benefits are assessed by applying a multi-criteria benefit-cost-assessment. For each grid reinforcement, its effects of the overall generation costs and the Security of Supply are put in the perspective to the possible annual costs (Task 2.3). After the grid development, each 2050 grid architecture is checked for its ability to be implemented and operated in the existing system. The assessment of the transmission technologies requires high knowledge of the developments towards 2050, which will be received from the supporting task (Task 2.4).

Annex A: Map of European clusters

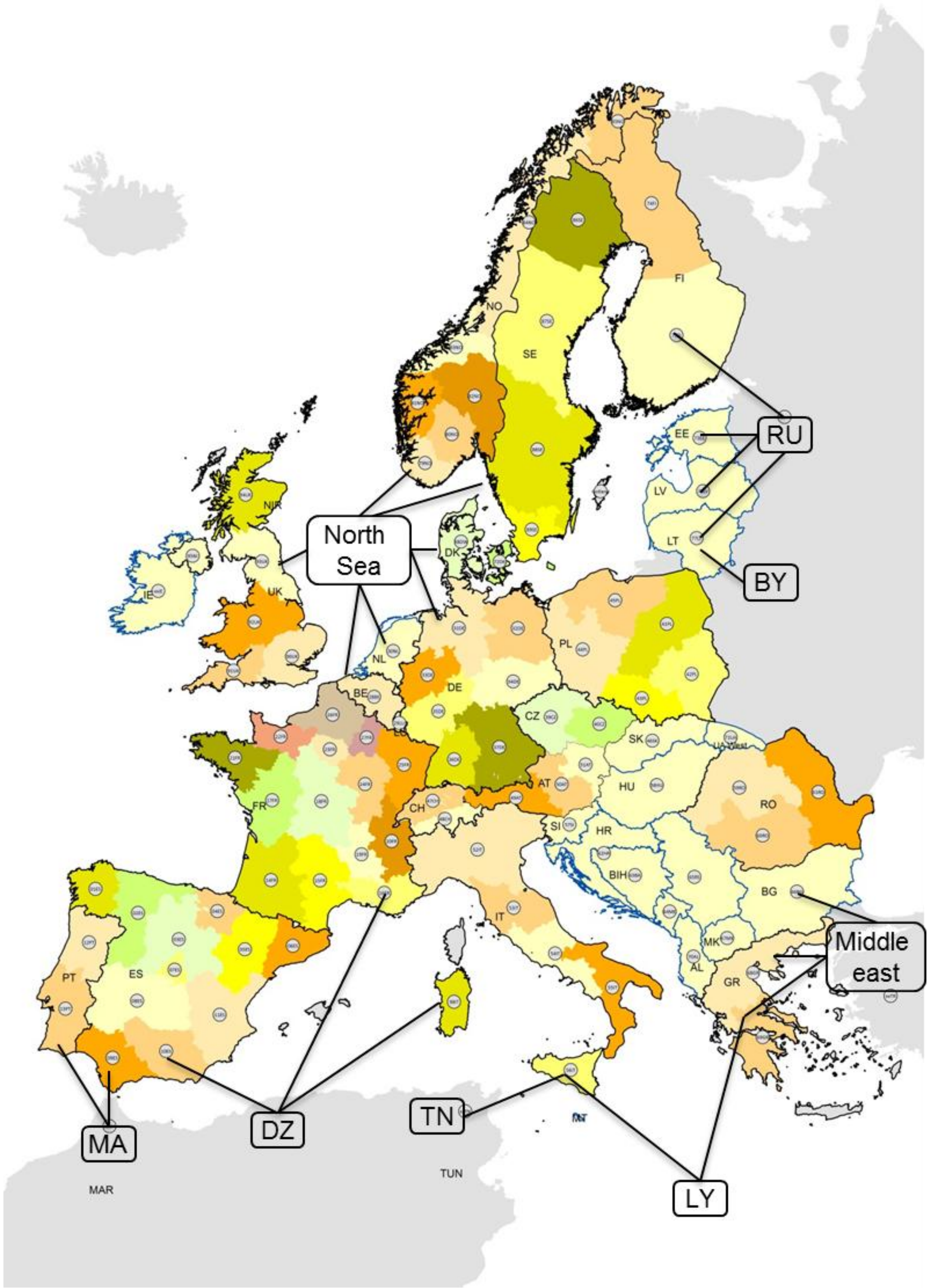

Figure 32: Map of the European cluster model

Annex B: Presentation of the system simulator: ANTARES

Antares is a sequential Monte-Carlo system simulator developed by RTE. It calculates generation and flows over Monte-Carlo years, at an hourly-step, to minimize the overall cost of the system.

Only the functionalities and parameters used by the eHighway project are described in this Annex, more details can be found in: M. Doquet, C. Fourment, J.M. Roudergues, "Generation & Transmission Adequacy of Large Interconnected Power Systems: A contribution to the renewal of Monte-Carlo approaches", PowerTech 2011, IEEE Trondheim

Antares uses a zonal description of the power system - areas are connected by links. An area can represent a group of countries, a country or a small region. Within the e-Highway project, each area is defined by the following set of data:

- **Load:** Different hourly time-series of load over one year can be provided, accounting for different meteorological conditions represented in proportion to their frequency of occurrence. For each Monte-Carlo year simulated, one of them will be picked at random so as to populate the sample in a statistically valid way.

- **Wind, solar and run-of-river generation:** As for load, different hourly time series of solar, wind and run of river generation can be provided. Likewise, for each Monte-Carlo year, one of each will be picked at random. When spatially correlated time-series are available for load and wind, solar and hydro energy, they are chosen on the basis of duly correlated draws.

- **Thermal units:** Different types of thermal plants can be defined. The maximal power, the marginal cost and the number of units are compulsory parameters for each type of units. In addition, minimal stable power, minimum up and down time and CO_2 emissions can be defined. Forced and planned outage rates and durations for each day of the year can be defined. They are used to generate time-series of available generation for each Monte-Carlo year to simulate.

- **Hydro with reservoir:** For hydro with reservoir, a daily maximal power and a size of reservoir can be defined as well as monthly time series of inflows (with spatial correlation factors between areas). For each Monte-Carlo year, one inflows time series is picked up at random. Weekly generation is defined by heuristics that take into account the level of hydro resources and that of the net demand to accommodate (raw load minus run of the river, wind power, and other "must-run" generation). Within each week, the hourly generation is finally determined by the general optimization (global minimization of the overall operating system cost, including all kinds of generation).

- **Storage:** Storage units are defined by their efficiency rate and their maximal power. The storage capacity can also be taken into account indirectly.

For the links, **direct and indirect transmission capacities** are defined (for copper plate simulations in T2.1, they are set to infinite) and, if necessary, **equivalent impedances** and hurdle costs (€/MWh going through the link) as well.

A **cost of unsupplied energy** has to be defined and is then taken into account by the optimization.

For each Monte-Carlo year, optimizations are run for each week to define the generation and flows that minimize the overall cost of the system taking into account all the parameters described previously (demand, available generation and its constraints, limited transmission capacities and equivalent impedances, hurdle costs, cost of unsupplied energy…). The result of the simulation is a set of data at an hourly scale for each area and link: overall cost, balance, hydro generation, thermal generation for the different types, unsupplied energy, spilled energy, flows on the links, marginal cost… Simulations are performed for the number of Monte-Carlo years defined by the user.

The key advantages of using a system simulator as Antares are:

- Simulations at an hourly scale are crucial to take into account the impact of the variations of demand and renewable generation: annual energy considerations do not guarantee adequacy at each hour and balanced countries over the year can still need high exchanges at some hours.

- Optimization is run on a weekly basis and not for each hour separately, meaning that the sequentially is kept: the minimal up and down time of plants is considered, storage cycles are realistic and hydro generation is used when it is the most necessary.

- Simulating a significant number of Monte-carlo years ensures more robust results because uncertainties such as renewable generation or availability of plants are smoothen over the years.

- So-called “market simulations” can be run taking into account a grid model. These simulations are thus called system simulations.

Annex C: Calculation of the annual demands per country and scenario

This Annex describes the methodology, assumptions, sources and reference material used to produce country level projections for final electricity demand (including network losses) in 2050 for each of the five e-Highway 2050 scenarios:

- ✓ x-5: Large scale RES & No emission
- ✓ x-7: 100% RES
- ✓ x-10: Big & Market
- ✓ x-13: Big, Nuclear and CCS
- ✓ x-16: Small and Local

High-level sensitivity analyses on the five scenarios have been also performed to consider the impact on final European electricity demand (including network losses) of changing:

- ✓ Growth rate of GDP per capita and population level; and
- ✓ Energy efficiency.

The results of this sensitivity analysis are also presented in this annex and in the supporting spreadsheet file as well.

Top-down approach

The country level projections were produced in line with the top-down approach, which is required for e-Highway2050 scenarios. ENTSO-E describes a top-down approach as follows:

- ✓ "a top-down approach, in which the load and generation evolution was constructed for all countries in a way that was compliant and coherent with the same macro-economic and political view of the future" [Dem-1]

  This means that common **policy** inputs across all countries in each e- Highway2050 scenario (e.g. for the extent of electrification, and for energy efficiency improvements) were used. For some data inputs, country-specific values where **both** of the following conditions are met were used:

- ✓ Need to allow for possible changes in the distribution of electricity demand between countries as a result of fundamental differences between countries that are not driven by energy policy – e.g. differences in economic growth; importance of heating in the energy mix; transport patterns etc.
- ✓ Data is available on a consistent basis from international studies (i.e. no reliance on specific national studies).

Throughout this chapter, it is highlighted where common European values were used and where country-specific values were used.

Overview of the methodology

Figure 30 summarises the four step process that is used to produce the country level projections for final annual electricity demand including losses in 2050[6].

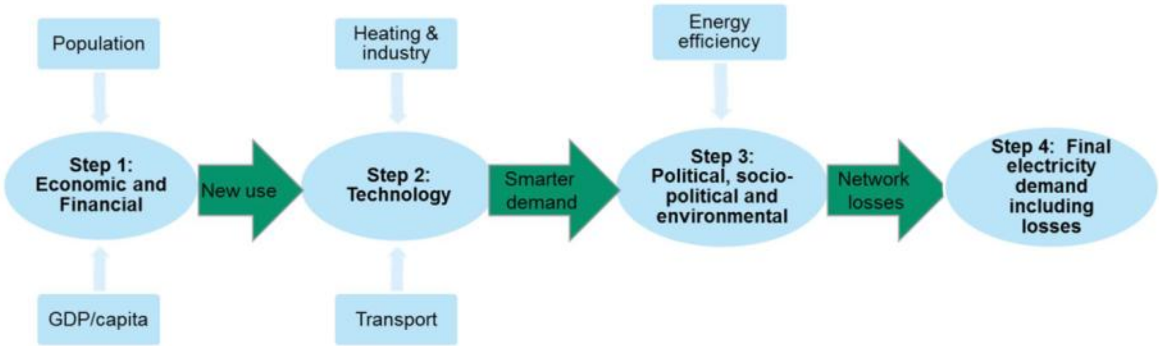

Figure 33: Process for projecting final annual electricity demand including network losses by country for 2050 in each e-Highway 2050 scenario[7]

The first three steps reflect the scenario criteria used in eHighway2050 Deliverable D1.2 [Dem-2] to group options (used to define strategies), uncertainties (used to define futures) and assumptions (fixed across all scenarios):

- ✓ Economic and financial;
- ✓ Technology; and
- ✓ Political, socio-political and environmental[8].

6 In a previous presentation of the methodology, it was suggested taking account for the impact of distributed generation on flows across the transmission network. Following further discussions with members of the e-HIGHWAY 2050 consortium, it was pointed outthat each cluster will be modelled on a copper plate basis (i.e. with no distinction between transmission-connected and distribution-connected generation). This means that for the flows between clusters, it is the total generation within a cluster that is important, rather than the split between transmission and distribution connected generation. Therefore the step related to distributed generation was removed from the methodology.

7 For the purpose of these annual electricity demand projections, ‘energy efficiency’ refers to Passive Demand Side technologies – e.g. insulation in buildings or new components that consume less (new fridges etc.). Active demand side technologies are considered in the scope for changing the hourly time series of demand, which is not in the scope of this particular note.

For each of these three steps, table 19 sets out the Demand data used to verbally define each scenario depicted in table 8.5 in [Dem-2]. In this chapter, proposed values are compared to the relevant boundary conditions for these pieces of demand data that are quantified in [Dem-2].It has to be mentioned that these four steps refer only to the definition of demand for the e-Highway 2050 scenarios and should not be confused with the overall G/D/E steps for quantification of the e-Highway 2050 scenarios described above.

	Scenario number	x-5	x-7	x-10	x-13	x-16
	Scenario name	**Large scale RES & no emissions**	**100% RES**	**Big & Market**	**Big Nuclear and CCS**	**Small and Local**
Step 1: Economic and Financial	**Population (demographic changes)**	Growth	Growth	Growth	Growth	Migration only
Step 2: Technology	**GDP increase**	Medium	Medium	Medium	Medium	Low
	New use	High	High	High	High	Low
Step 3: Political, socio-political and environmental	**Energy efficiency**	Low	High	Medium	Low	High

Table 20: Extract from table 8.5 in e-Highway 2050 Deliverable D1.2 [Dem-2]

As part of WP3 of the e-HIGHWAY 2050 project, detailed research is carried out into the different elements of the technology criteria. The draft WP3 report on demand (M3.1 – demand) describes similar drivers of annual demand volumes to the ones set out in our 4 Step methodology.

WP3 will quantify the uncertainties around three demand-side technologies in 2050:

- **LED lighting** - the impact of greater use of LED lighting should be captured in the energy efficiency step. However, the top-down approach implies that lightning demand is not excluded. Therefore, the values from WP3 on this technology will be useful as a sense check on the pos-

[8] In [Dem-2], energy efficiency is mentioned in the discussion of options for both the technology criteria and the economic and financial criteria. However, in this note, energy efficiency under the heading of 'political, socio-political and environmental' is coverd in line with the groupings set out in the synthesis chapter (Section 7) of [Dem-2].

sible source of energy efficiency improvements, but will not be directly comparable to any of the values, which are produced in the analyses at hand.

- **Electric vehicles** – this relates to a major part of the work in Step 2 (Technology), in particular in relation to kWh/km (conversion efficiency) and number of electric vehicles in 2050. These figures are broadly comparable with the values that are used to produce the annual electricity demand projections shown in this chapter[9].
- **Heat pumps** – the use of heat pumps for heating is a major part of the work in Step 2 (Technology)[10]. Recently obtained 2050 heat pump values are available from WP3. The differences between the approaches at hand (i.e. bottom up WP3 and top down WP2) mean that there were few directly comparable values between the WP3 values and the figures reported in D2.1. E.g. the WP3 data reports number of heat pump units, whereas D2.1 considers the percentage of total heat demand (TWh) met by heat pumps. Furthermore, the D2.1 assumptions are well within the ranges quoted in the WP3 work so far. Further work in WP3 will be carried out to assess how improved data might be used in further steps of the work when modelling demand hourly profiles.

The final step in the process set out in figure 30 adds network losses to final electricity demand. As these losses primarily consist of losses on the lower voltage distribution networks, they will not be captured by the topography analysis in WP2.3. Therefore, a fixed estimate for the loss rate (as described below) was used.

This note and the accompanying Excel file contains projections for 2050 electricity demand (including network losses) for the countries set out in table 20. The figures shown for Serbia in this chapter always include Kosovo.

Furthermore, figures for UK and (the Republic of) Ireland were presented in line with the terminology used in the preliminary assessment for e-Highway 2050, i.e. representing volumes at country level. As it is moved to model time series, the split will be changed to Great Britain, and to the single Irish electricity market (i.e. volumes for Northern Ireland will be moved from the UK total to the Ireland total to reflect the current configuration of electricity markets).

Economic and financial criteria

9 In each scenario, the figures for the total number of electric vehicles are about 10% higher than the WP3 equivalent. In addition, the (implied) 2050 figure (after energy efficiency improvements) for the kWh required per km of travel is about 10-20% higher than WP3 (depending on scenario). If the WP3 figures for these two assumptions were used, the estimate that total electricity demand (including network losses) would fall by 3-4% across Europe, depending on the scenario. This seems within a reasonable range of tolerance, and therefore the WP2.1 values (which are consistent with other parts of our scenario) were retained. This also seems a prudent approach as it is not clear that the source studies for the WP3 values are exactly comparable to the values produced in WP2.1 (e.g. countries covered, population and GDP assumptions etc.).

10 The use of heat pumps for cooling is covered by Step 1 (Economic and Financial) rather than explicitly in Step 2.

The relevant economic and financial criteria for the production of end-use electricity demand projections are:

- **uncertainty** – Demographic change (European Growth/Migration); and
- **uncertainty** – GDP growth (High/Medium/Low).

The other uncertainties listed under economic and financial criteria relate to fuel and carbon allowance prices, which were not taken into account in the projection of annual electricity demand (including network losses) by country in 2050.

In table 25 (at the end of this section), the results from a sensitivity analysis of varying the assumptions for GDP/capita and population from those used in the main scenarios are reported.

Demographic change

e-Highway 2050 Deliverable D1.2 [Dem-2] proposes two possibilities for the 'Demographic change' uncertainty – 'Growth' and 'Migration-only'.

In 'Growth', it is proposed that the population in each country in 2050 is taken from the Eurostat 'Convergence' scenario [Dem-5]. This results in a European population figure of 560m in 2050, an increase of 27m (5%) between 2010 and 2050[11]. This compares to a 3% increase between 2010 and 2050 proposed for 'Growth' in [Dem-2] (in line with the EU Energy Roadmap 2050 [Dem-3]).

In 'Migration-only', it is proposed fixing the total 2050 population across all countries at the total 2010 population level, which is in line with the recommendations set out in [Dem-2]. Eurostat figures [Dem-4][12] show a total 2010 population level of 533m for the countries covered in this study (rather than the figure of 500m quoted in [Dem-2], which appears to be for the EU-27 [Dem-15]). Whilst the total population level will remain the same as in 2010, the distribution of population between countries will be allowed to change. The distribution of population between countries will be the same distribution as that used in the 'Growth' scenario. This means that for every country, the population level in the 'Growth' scenario is higher than in the 'Migration' scenario.

The proposed population level in 'Growth' is slightly higher than the other population studies quoted in [Dem-2]. For the EU-27 only, the proposed 2050 population is 498m in 'Migration-only' and 524m in 'Growth'. This compares to:

- 500m – ECF Roadmap 2050 [Dem-7];
- 512m – IEA ETP 2012 [Dem-8]; and
- 515m – EU Energy Roadmap 2050 [Dem-3] and EREC RE-thinking 2050 [Dem-9].

[11] This equates to an annual growth rate of 0.1%p/a between 2010 and 2050

[12] For countries not covered by Eurostat, World Bank data for the 2010 population [Dem-19] and the (weighted) average **Eurostat** growth rate were used.

It was decided to use the Eurostat scenario for all countries in 'Growth' because it is based on an external projection produced consistently at a European level (with country-specific information[13]). In addition, for many of the countries, the 2050 population levels in 'Growth' are in line with the maximum figures shown in table 4.1 in [Dem-2]. The proposed European population for 'Growth' of 558m is also close to the equivalent figure for the Medium (541m) scenario produced by the UN [Dem-6]. For reference, the equivalent figures for the High and Low scenarios produced by the UN are 608m and 478m respectively.

Table 21 describes the 2050 population figures that were used for each country for 'Migration-only' and 'Growth' (alongside figures for 2010).

Although for some countries (for example Germany, Bulgaria and Romania) there is a projected decrease in population by 2050 in 'Growth', it was judged that this is to be consistent with the top-down approach to scenario development (in which the overall population must grow in this scenario rather than the population in every single country also having to grow).This is consistent with other population scenarios to 2050 –for example, the UN World Population Prospects which has three scenarios (High, Medium and Low variant) for 2050 as shown in table 21 – this shows projected decrease in German population in the Medium variant even though there is a projected overall increase in European population. For Bulgaria and Romania, there is a fall in population in all 3 of the UN variants.

Year	**2010**	**2050 (Migration-only)**	**2050 (Growth)**
Source	Eurostat [Dem-4]	Set to total 2010 levels (with a country level distribution determined by the 'Growth' scenario)	Eurostat Convergence scenario [Dem-5]
Scenario		x-16	x-5, x-7, x-10 and x-13
Total	533,212	533,212	560,189
Austria	8,375	8,537	8,969
Belgium	10,84	12,493	13,126
Bosnia Herzegovina	3,76	3,744	3,933
Bulgaria	7,564	5,615	5,899
Croatia	4,418	4,399	4,621
Cyprus	803	1,038	1,09
Czech Republic	10,507	10,154	10,668
Denmark	5,535	5,747	6,038

[13] The population figures are shown in thousands to be consistent with table 4.1 in [Dem-2].

Year	2010	2050 (Migration-only)	2050 (Growth)
Source	Eurostat [Dem-4]	Set to total 2010 levels (with a country level distribution determined by the 'Growth' scenario)	Eurostat Convergence scenario [Dem-5]
Scenario		x-16	x-5, x-7, x-10 and x-13
Estonia	1,34	1,155	1,213
Finland	5,351	5,451	5,727
France	64,714	69,66	73,184
FYROM	2,061	2,052	2,155
Germany	81,743	67,397	70,807
Greece	11,305	11,018	11,576
Hungary	10,014	8,735	9,177
Ireland	4,468	5,908	6,207
Italy	60,34	62,741	65,915
Latvia	2,248	1,71	1,797
Lithuania	3,329	2,676	2,812
Luxembourg	502	670	704
Montenegro	631	629	661
Netherlands	16,575	16,522	17,358
Norway	4,858	6,059	6,366
Poland	38,167	32,879	34,543
Portugal	10,638	10,088	10,598
Romania	21,462[14]	17,593	18,483
Serbia	9,067	9,027	9,484
Slovakia	5,425	5,07	5,326
Slovenia	2,047	2,013	2,115

14 The statistical data on the population of Romania were updated in August 2013 and changed to 20,294,683 inhabitants. The initial data for this study were retrieved just before August 2013. Using this updated data as initial data does not significantly change the results of this study. Therefore, the calculations conducted in this analysis remained unchanged.

Year	**2010**	**2050 (Migration-only)**	**2050 (Growth)**
Source	Eurostat [Dem-4]	Set to total 2010 levels (with a country level distribution determined by the 'Growth' scenario)	Eurostat Convergence scenario [Dem-5]
Scenario		x-16	x-5, x-7, x-10 and x-13
Spain	45,989	50,151	52,688
Sweden	9,341	10,69	11,231
Switzerland	7,786	8,864	9,313
UK	62,008	72,727	76,406

Table 21: Country-specific outcomes for demographic change uncertainty (thousands)

Variant		Low Variant	Medium Variant	High Variant
Year	2010	2050	2050	2050
Overall European figure	531,042	478,017	540,614	608,225
Austria	8,394	7,456	8,427	9,478
Belgium	10,712	10,273	11,587	12,989
Bosnia and Herzegovina	3,76	2,566	2,952	3,385
Bulgaria	7,494	4,737	5,459	6,26
Croatia	4,403	3,373	3,859	4,396
Cyprus	-	-	-	-
Czech Republic	10,493	9,386	10,638	11,984
Denmark	5,55	5,219	5,92	6,672
Estonia	1,341	1,076	1,233	1,403
Finland	5,365	4,963	5,611	6,308
France	62,787	64,209	72,442	81,273
FYROM	2,061	1,64	1,881	2,152
Germany	82,302	66,186	74,781	84,084
Greece	11,359	10,356	11,647	13,041
Hungary	9,984	8,091	9,243	10,482
Ireland	4,47	5,356	6,038	6,764
Italy	60,551	52,86	59,158	65,918
Latvia	2,252	1,653	1,902	2,174
Lithuania	3,324	2,435	2,813	3,224
Luxembourg	-	-	-	-
Montenegro	-	-	-	-
Netherlands	16,613	15,187	17,151	19,247
Norway	4,883	5,381	6,063	6,794
Poland	38,277	30,428	34,906	39,748
Portugal	10,676	8,271	9,379	10,584
Romania	21,486	16,148	18,535	21,18

Variant		Low Variant	Medium Variant	High Variant
Year	**2010**	**2050**	**2050**	**2050**
Serbia	9,856	7,631	8,797	10,085
Slovakia	5,462	4,578	5,241	5,958
Slovenia	2,03	1,767	1,994	2,239
Spain	46,077	45,868	51,354	57,285
Sweden	9,38	9,679	10,916	12,244
Switzerland	7,664	6,976	7,87	8,829
UK	62,036	64,268	72,817	82,045

Table 22: UN World Population prospects variants for 2050 (thousands)

GDP per capita growth

e-Highway 2050 Deliverable D1.2 [Dem-2] proposes three possible outcomes for the ‘GDP growth’ uncertainty – ‘High’, ‘Medium’ and ‘Low’. However, only ‘Medium’ and ‘Low’ are used in the five main e-Highway 2050 scenarios.

Outcomes are defined as follows:

- ‘Medium’ is based on projected country level GDP/capita growth rates from the OECD study [Dem-11], which produces an overall European CAGR[15] for GDP/capita of 1.53%; and
- ‘Low’ is based on a projected overall European CAGR for GDP/capita from the CEPII study [Dem-10] of 1.26%. Country level growth rates will then be equivalent to the OECD study CAGRs but reduced by an identical amount equivalent to the difference between the two studies’ total GDP/capita growth rates (0.26%).

This means that that for every country, the annual GDP/capita growth rate in the ‘Central’ scenario is 0.27% higher than in the ‘Low’ scenario.

The overall European GDP/capita growth rates in ‘Low’ and ‘Medium’ fall outside the boundaries of 1.7% and 2.3% proposed in the e-Highway 2050 boundary paper [Dem-2]. However, the 2.3% maximum figure quoted in [Dem-2] appears to be a straight-line average of the highest figure for each country from the OECD and CEPII studies. When weighting by the 2010 level of GDP in each country, the average of the maximum figures falls to 1.6% (because the large countries typically have lower growth rates).

For reference, the equivalent GDP/capita annual growth rates from the other studies quoted in [Dem-2] are as follows[16]:

[15] Compound annual growth rate

- 1.2%: low growth sensitivity in EU Energy Roadmap 2050 [Dem-3];
- 1.6%: reference scenario in EU Energy Roadmap 2050 [Dem-3];
- 1.7%: Eurelectric Power Choices [Dem-13];
- 1.9%: ECF Roadmap 2050 [Dem-7]; and
- 2.0%: high growth sensitivity in EU Energy Roadmap 2050 [Dem-3].

These figures support the proposed values for 'Low' and 'Medium', which equate to overall European growth of 1.3%/a and 1.5%/a respectively. It would be recommended that, if a scenario with 'High' GDP growth is required, a suitable European growth of 2.0%/year should be used. This is in line with the EU Energy Roadmap high growth sensitivity [Dem-3].

Table 22 shows the country-specific CAGRs (2010-2050) we have used for GDP/capita in 'Low' and 'Medium'[17].

Primary source	**CEPII [Dem-10]**		**OECD [Dem-11]**	
Scenario	**x-16**	**Low**	**x-5, x-7, x-10, x-13**	**Medium**
Overall European figure	**1.26%**		**1.5%**	
Austria	1.0%		1.3%	
Belgium	1.3%		1.6%	
Bosnia and Herzegovina	1.2%		1.5%	
Bulgaria	4.0%		4.2%	
Croatia	1.2%		1.5%	
Cyprus	1.2%		1.5%	
Czech Republic	1.9%		2.2%	
Denmark	1.3%		1.6%	
Estonia	2.3%		2.6%	
Finland	1.3%		1.6%	
France	1.0%		1.3%	

16 These figures differ slightly from the values presented in Section 4.3 of [Dem-2] as some of those values related to annual growth in total GDP (which is also influenced by population growth) rather than GDP/capita. Also, [Dem-2] listed a GDP growth figure of 2.0%/year to 2050 from the IEA WEO (and sourced to D1.1 [Dem-43]). However, we have not been able to cross-reference that number with IEA WEO 2012 [Dem-12] or IEA WEO 2011, or [Dem-43], as we can only find GDP growth rate projections for Europe of 1.7% (2010-2020) and 1.8% (2020-2035).

17 As 'High' GDP/capita growth is not part of any of the 5 main e-Highway 2050 scenarios, it is not shown in Table 3. If 'High' was to be used, we would recommend basing country- specific GDP/capita growth rates on an overall European growth rate in GDP/capita of around 2%.

FYROM	1.2%	1.5%
Germany	1.2%	1.5%
Greece	1.1%	1.4%
Hungary	2.0%	2.3%
Ireland	0.8%	1.1%
Italy	1.0%	1.3%
Latvia	5.9%	6.1%
Lithuania	5.4%	5.7%
Luxembourg	0.0%	0.3%
Montenegro	1.2%	1.5%
Netherlands	1.3%	1.6%
Norway	1.3%	1.6%
Poland	1.6%	1.9%
Portugal	1.2%	1.5%
Romania	4.1%	4.4%
Serbia	1.2%	1.5%
Slovakia	1.8%	2.1%
Slovenia	1.5%	1.8%
Spain	1.1%	1.4%
Sweden	1.3%	1.6%
Switzerland	1.4%	1.7%
UK	1.3%	1.6%

Table 23: Country-specific outcomes in GDP/capita (CAGR, 2010-2050) Source: CEPI [Dem-10] and OECD [Dem-11]

GDP

Using the assumed growth rates in population and GDP/capita, a 2050 value in GDP for each country was projected. Table 23 shows the resulting CAGR of GDP between 2010 and 2050 for each of the relevant scenarios, both overall for Europe and by country.

Demographic change	Migration-only	Growth

GDP growth (per capita)	**Low**	**Medium**
Scenario	**x-16**	**x-5, x-7, x-10 and x-13**
Overall European figure	**1.4%**	1.8%
Austria	1.1%	**1.5%**
Belgium	1.7%	**2.1%**
Bosnia and Herzegovina	1.2%	**1.6%**
Bulgaria	3.2%	**3.6%**
Croatia	1.2%	**1.6%**
Cyprus	1.9%	**2.3%**
Czech Republic	1.8%	**2.2%**
Denmark	1.4%	**1.8%**
Estonia	2.0%	**2.3%**
Finland	1.4%	**1.8%**
France	1.2%	**1.6%**
FYROM	1.2%	**1.6%**
Germany	0.7%	**1.1%**
Greece	1.1%	**1.5%**
Hungary	1.7%	**2.1%**
Ireland	1.5%	**1.9%**
Italy	1.1%	**1.5%**
Latvia	5.1%	**5.5%**
Lithuania	4.9%	**5.3%**
Luxembourg	0.8%	**1.2%**
Montenegro	1.2%	**1.6%**
Netherlands	1.3%	**1.7%**
Norway	1.9%	**2.3%**
Poland	1.3%	**1.6%**
Portugal	1.1%	**1.5%**
Romania	3.6%	**4.0%**

Demographic change	**Migration-only**	**Growth**
GDP growth (per capita)	**Low**	**Medium**
Scenario	**x-16**	**x-5, x-7, x-10 and x-13**
Serbia	1.2%	**1.6%**
Slovakia	1.7%	**2.1%**
Slovenia	1.5%	**1.9%**
Spain	1.4%	**1.7%**
Sweden	1.7%	**2.1%**
Switzerland	1.8%	**2.2%**
UK	**1.7%**	**2.1%**

Table 24: Country-specific GDP growth rates (CAGR, 2010-2050)

<u>The relationship between GDP and Demand</u>

GDP growth rates as depicted in table 24 were used to project 'business as usual' electricity demand based on observed (country-specific) historical relationships between GDP and electricity demand. The econometric modelling of this relationship is based on the relationships used in the leading European electricity market simulation software, BID3. BID3 is used by TSOs, energy companies and regulators to project the European electricity market into the future.

Figure 34 shows the projected 'business as usual' electricity demand at a European level for each GDP scenario, as well as the historical relationship.

The regression model is used to generate annual electricity demand projections for each year out into the future. It consists of both common and country specific parameters for GDP growth, lagged GDP and lagged power demand. The regression also includes a country specific constant term that captures country specific relations which is constant over time. In some cases, the country specific coefficient is not significantly different from zero. If so, the country specific coefficient will be excluded, and the country will only have the common coefficient.

This regression model has then informed the estimation of the long-term relationship between GDP growth and electricity demand growth as shown in Table 24. This long-term relationship is slightly sensitive to the GDP growth experienced over the same period. As such, scenario x-16 has a slightly different relationship between GDP and demand due to the lower total GDP projected in this scenario in 2050.

The 11 countries marked with an asterisk in table 24 all have a long-term relationship between GDP and demand[18] (0.71 to 0.78) based on the common European level. This reflects that in general our regression model has not found statistically significant country coefficients.

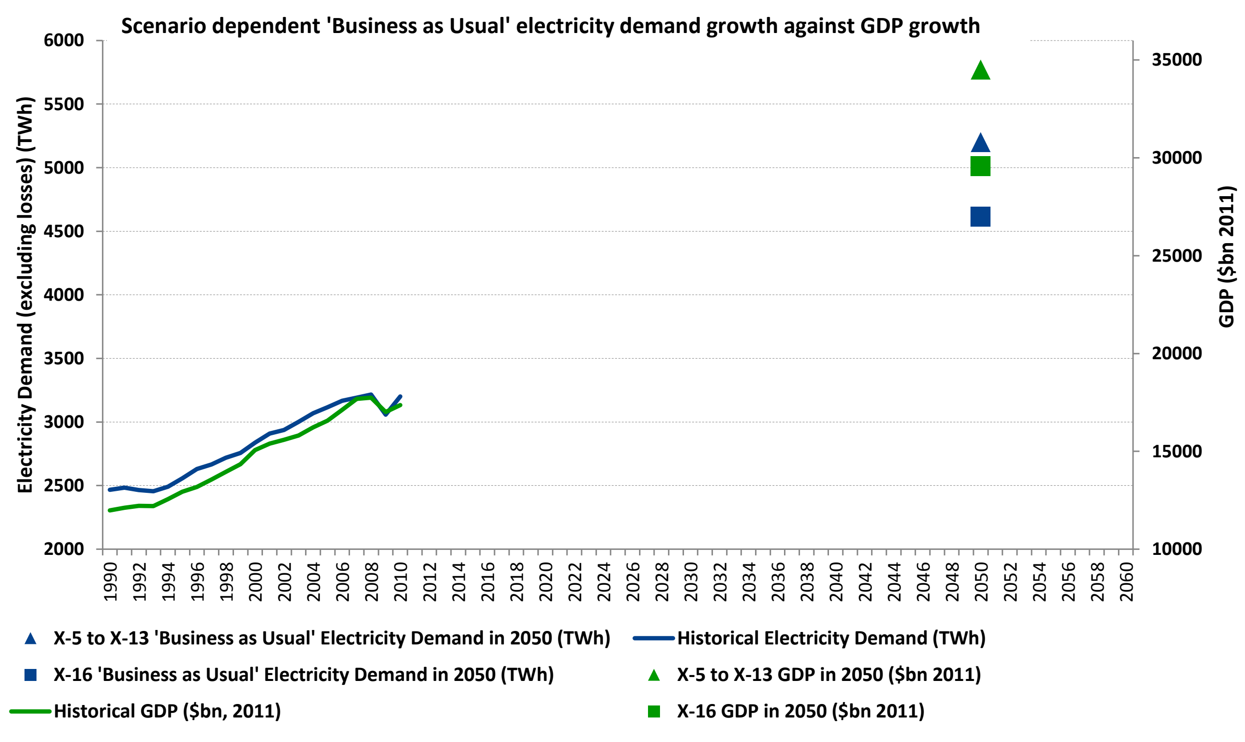

Figure 34: Historical relationship between GDP and electricity demand , as well as projected 'BAU' electricity demand for each GDP scenario

Demographic Change	**Migration-only**	**Growth**
GDP growth (per capita)	**Low**	**Medium**
Time Period	**2010-2050**	**2010-2050**
Scenario	**x-16**	**x-5, x-7, x-10 and x-13**
Overall European figure	**0.62**	**0.62**
Austria*	0.75	0.74
Belgium	0.50	0.48
Bosnia and Herzegovina*	0.76	0.74
Bulgaria	0.14	0.13

[18] For these countries, the percentage change in electricity demand in 2050 for a 1% change in GDP is between 0.71 to 0.78.

Demographic Change	Migration-only	Growth
GDP growth (per capita)	Low	Medium
Time Period	2010-2050	2010-2050
Scenario	x-16	x-5, x-7, x-10 and x-13
Croatia*	0.76	0.74
Cyprus	1.52	1.56
Czech Republic	0.22	0.21
Denmark	0.25	0.23
Estonia*	0.73	0.71
Finland	0.32	0.30
France*	0.80	0.78
FYROM	0.63	0.61
Germany*	0.76	0.75
Greece*	0.74	0.73
Hungary*	0.75	0.73
Ireland*	0.72	0.71
Italy	1.25	1.27
Latvia	0.61	0.60
Lithuania	0.63	0.61
Luxembourg	0.55	0.53
Montenegro	0.19	0.18
Netherlands*	0.74	0.73
Norway	0.20	0.19
Poland	0.29	0.27
Portugal	0.89	1.10
Romania	0.10	0.09
Serbia	0.19	0.18
Slovakia	0.16	0.15
Slovenia	0.36	0.34

Demographic Change	**Migration-only**	**Growth**
GDP growth (per capita)	**Low**	**Medium**
Time Period	**2010-2050**	**2010-2050**
Scenario	**x-16**	**x-5, x-7, x-10 and x-13**
Spain	1.46	1.51
Sweden	0.09	0.08
Switzerland*	0.75	0.73
UK	0.16	0.15

Table 25: Percentage change in electricity demand in 2050 for a 1% change in GDP

Sensitivity on GDP

To test the effects of GDP change, sensitivity analysis of the five e-HIGHWAYS 2050 scenarios was carried out. In this sensitivity analysis, the alternative population and GDP/capita levels in each scenario were used – i.e. using 'Migration-only' and Low GDP/capita growth in x-5, x-7, x-10 and x-13, and using 'Growth' and Medium GDP/capita in x-16.

Consequently, European GDP in 2050 decreased by 14% in x-5, x-7, x-10 and x-13 with final electricity demand falling by 10-11% (depending on the scenario). In x-16, a 17% increase in GDP[19] results in a 12% increase in demand.

	Scenario number	**x-5**	**x-7**	**x-10**	**x-13**	**x-16**
Population	**Scenario name**	**Large scale RES & no emissions**	**100% RES**	**Big & Market**	**Big Nuclear and CCS**	**Small and Local**
Main scenario	**Population**	560m ('Growth')	560m ('Growth')	560m ('Growth')	560m ('Growth')	533m ('Migration-only')
	Annual GDP/capita growth	1.53% ('Central')	1.53% ('Central')	1.53% ('Central')	1.53% ('Central')	1.26% ('Low')

[19] The € change in GDP is the same in absolute terms (albeit in the opposite direction) for the sensitivity on the other scenarios. However, the % change in GDP is larger in x-16 as the GDP is lower in the main x-16 scenario than in the other 4 scenarios.

	Annual final electricity demand including network losses (TWh)	5364	4381	4387	4854	3161
Sensitivity	**Population**	533m ('Migration-only')	533m ('Migration-only')	533m ('Migration-only')	533m ('Migration-only')	560m ('Growth')
	Annual GDP/capita growth	1.26% ('Low')	1.26% ('Low')	1.26% ('Low')	1.26% ('Low')	1.53% ('Central')
	Annual final electricity demand including network losses (TWh)	4820	3936	3920	4337	3547
Change in final demand from Main Scenario	**TWh**	**Minus 544**	**Minus 444**	**Minus 468**	**Minus 517**	**Plus 386**
	% of final electricity demand (including network losses)	**-10%**	**-10%**	**-11%**	**-11%**	**12%**

Table 26: Sensitivity on alternative GDP levels

Technology criteria

The relevant technology criteria for the production of end-use electricity demand projections are:

- **Uncertainty** – Electrification of transport, heating and industry (Residential/Large scale/All); and
- **Assumption** – Maturity of RES and DSM technologies[20].

The other options and uncertainties relate to generation and storage, which are covered by the contribution of other partners to WP2.1.

In Step 2, the increase in electricity demand arising from the electrification of heating and transport is projected – this is designed to capture policy-driven changes that result in electricity accounting for an increased share of the energy mix for heat and transport.

[20] In projecting annual demand, this fixed assumption is interpreted across scenarios to also apply to the maturity of new use technologies in general (e.g. conversion efficiency of vehicle batteries) rather than just the load-shifting capabilities.

For each country, the general approach is to calculate the increase in electricity demand for transport (or heating) as the product of:

- the increase in end-use energy met by electricity; and
- the rate of conversion of electricity to the end-use energy (e.g. number of km per kWh for an electric vehicle).

Scenario description

In Section 7.1 of [Dem-2], three possible outcomes are listed for the uncertainty of electrification of transport, heating and industry – Residential, Large Scale, All. These terms are used in the descriptions of the 5 e-Highway 2050 futures, both verbally and in table 8.1.

However, different terminology is used when describing the parameter for the level of demand according to new uses (parameter 9[21]), which has two levels across the 5 main scenarios (High and Low).

Similarly, in the description of the scenarios in Section 8.4 of [Dem-2], the verbal description identifies whether electrification is primarily at residential or large scale level, with the summary in table 8.5 in [Dem-2] differentiating between High or Low new use. This is summarised in table 26:

Scenario	**x-5 and x-7**	**x-10 and x-13**	**x-16**
Electrification of heating and transport (u8)	Large scale and domestic	Large scale	Domestic
Level of new use (parameter 9)	High	High	Low

Table 27: Variation in electrification of demand between scenarios

Source: e-Highway 2050 Deliverable D1.2 [Dem-2]

Developing demand projections that were consistent with both the verbal description of where electrification occurred (i.e. Residential and/or Large Scale) and with the magnitude of demand from new use (High or Low) was a challenging task. This was complex by three factors:

- For transport, the scope for electrification at residential level appears to be larger than at centralised/large-scale level – this particularly raises an issue for scenarios x-10 and x-13, which are required to have primarily large scale electrification and high levels of new use;
- The verbal description of scenario x-16 suggests an (absolutely) high level of residential electrification, but table 8.5 states a low level of new use; and

[21] Electrification of heating and transport (u8) is shown to map onto parameter 9 (level of demand according to new uses) in table 8.4 in [Dem-2].

- Electrification of heating and transport is typically seen as an important part of meeting the overall GHG targets – therefore, it does not seem feasible to have low absolute levels of electrification in any of the main e-Highway2050 scenarios. Hence, the 'Low' levels of new use in scenario x-16 were interpreted to be lower than in the other scenarios, but still represent significant levels of electrification

Electrification of transport

Energy use in surface transport[22] in Europe is currently dominated by private cars (60%) and road freight (33%), according to DGTREN figures for 2010 [Dem-15][23].

We have therefore focussed on these two forms of transport, mapping them onto the terms used for the electrification[24] uncertainty as follows:

- large scale – road freight; and
- residential – passenger vehicles[25].

A major challenge for the scenario quantification with respect to transport is that there appears to be much lower scope for electrification of road freight than passenger vehicles (despite energy use by each category being similar orders of magnitude). This is because around 60% of the tonne km for freight vehicles has historically been done by heavy trucks[26] (typically over 12 tonnes). By 2050, these vehicles are not expected to draw on electricity from the grid but rather take the form of hybrid electric vehicles (HEVs, where the electricity is generated by braking) or fuel cell electric vehicles[27].

This means that the maximum potential increase in electricity demand from electrification of large scale transport is estimated to be around a quarter of the comparable figures from the electrification of passenger vehicles. Therefore, the scenarios with 'High' new use (x-5, x-7, x-10 and x-13) all have the majority of transport electrification at the residential level.

This is highlighted in table 27, which summarises the level of new use from centralised and decentralised transport by scenario (excluding the impact of the energy efficiency assumption in Step 3). Thereby it is shown how for each scenario, it has been tried to balance the requirements of the description on the elec-

22 We have not taken into account any scope for electrification of aviation, as this issue is not raised in the scenario description.

23 The remaining 7% of energy used in surface transport is split between rail (3%), public road transport (2%) and inland navigation (2%).

24 When referring to electric vehicles in this note, vehicles that draw electricity from the grid are meant. Therefore, this does not include fuel cell electric vehicles or hybrid vehicles that use electricity generated by braking.

25 Other possible interpretations of 'large scale' could be centralised charging of car batteries (e.g. through a battery swapping scheme) and/or the use of electricity to produce hydrogen to power passenger vehicles. In both cases, the location of the electricity demand for passenger vehicles would neither affect the annual demand volumes nor the network modelling directly (as a copper plate network is assumed within a cluster, allowing no distinction between transmission and distribution connected demand). It could though affect the scope for DSM, which might be greater through a more centralised charging approach.

26 From Eurostat Transport data [Dem-33]

27 As described for example in European Commission's 'EU Transport GHG: Routes to 2050?' study [Dem-14].

trification uncertainty (u8) and the new use parameter. The derivation of these numbers is explored in more detail in the subsequent sections, which in turn focus on passenger vehicles and then on road freight transport.

For reference, final electricity demand in residential transport (after reduction for energy efficiency in Step 3) accounts for about 6-9% of overall final electricity demand (including network losses) depending on scenario. Final electricity demand in large scale transport (after reduction for energy efficiency in Step 3) accounts for about 1-3% of overall final electricity demand (including network losses) depending on scenario.

This means that whilst the projections of electricity demand growth in Step 1 could include some increase in electrification of trains (if the historic demand growth included increased electrification of trains), it is not explicitly considered the electrification of trains in Step 2.

Scenario		**x-5 and x-7**	**x-10 and x-13**	**x-16**
Electrification of heating and transport (u8)		Large scale and domestic	Large scale	Domestic
Level of new use (parameter 9)		High	High	Low
Transport	Residential	749 TWh	564 TWh	370 TWh
	Large scale	149 TWh	187 TWh	55TWh

Table 28: New use from decentralised and centralised transport, without energy efficiency (2050, total TWh across all countries)

For reference, final electricity demand in residential transport (after reduction for energy efficiency in Step 3) accounts for about 6-9% of overall final electricity demand (including network losses) depending on scenario. Final electricity demand in large scale transport (after reduction for energy efficiency in Step 3) accounts for about 1-3% of overall final electricity demand (including network losses) depending on scenario.

As part of the analysis of future electricity demands within the transport sector, the future role that electrification of the railway network could have was examined. Projected levels of energy demand in the transport sector were considered as set out in the EU Energy Trends to 2030 [Dem-15]. This showed the rail network as representing only 2% of transport energy use in 2030, compared to private cars and motorcycles with 44% and truck activity at 33%. As such it was decided that the railway network should not be included explicitly in the modelling of future electricity demand from transport. Furthermore, this is consistent with the recommendation in M3.1 (demand) from WP3 to not look at the electrification of railways since "impact will remain limited despite the number of km*passengers which is expected to grow" (table 4.7 in M3.1).

This means that whilst the projections of electricity demand growth in Step 1 could include some increase in electrification of trains (if the historic demand growth included increased electrification of trains), we have not explicitly considered the electrification of trains in Step 2.

Passenger vehicles

Two types of electric passenger vehicles – fully electric vehicles (EVs), and plug-in hybrids (PHEVs) were considered. This matches the demand technology categorisation that is being used in WP3.

According the general approach for Step 2, there are two key components in the projection of 2050 electricity demand from electric passenger vehicles in each scenario:

- Estimation of end-use energy demand met by electric passenger vehicle by country in each scenario (i.e. kilometres travelled by electric passenger vehicles); and
- Conversion efficiency, which is assumed to be the same for all countries and in all scenarios (i.e. kWh used per km).

Kilometres travelled by EVs and PHEVs

The projected kilometres travelled by EVs and PHEVs for each country in each scenario are based on the following steps:

- Total vehicle km (all vehicles) = average km per vehicle * total vehicles
- Km travelled by EV = Total vehicle km *EV share of km
- Km travelled by PHEV = Total vehicle km *PHEV share of km

The key elements of this formula are calculated as follows:

- **Average number of kilometres travelled per passenger vehicle per year** – It is assumed that the 2050 level for each country remained unchanged from current levels[28], which are shown in the following table:

Country	2010	2050
Austria	13,792	13,792
Belgium	13,456	13,456
Bosnia and Herzegovina*	11,496	11,496
Bulgaria	8,64	8,64
Croatia*	11,496	11,496
Cyprus	8,327	8,327
Czech Republic	12,677	12,677
Denmark	17,285	17,285

[28] This was calculated using passenger kilometres per year from DGTREN [Dem-15] and average occupancy rates from the European Environment Agency [Dem-21]. Where no country figures were available, the average European figure of 11,496km was used.

Country	2010	2050
Estonia	11,542	11,542
Finland	14,107	14,107
France*	14,938	14,938
FYROM	11,496	11,496
Germany*	13,891	13,891
Greece*	11,496	11,496
Hungary*	8,769	8,769
Ireland*	11,496	11,496
Italy	13,518	13,518
Latvia	16,467	16,467
Lithuania	14,858	14,858
Luxembourg	12,547	12,547
Montenegro	11,496	11,496
Netherlands*	14,008	14,008
Norway*	11,496	11,496
Poland	9,62	9,62
Portugal*	11,496	11,496
Romania	9,84	9,84
Serbia*	11,496	11,496
Slovakia	8,957	8,957
Slovenia	14,712	14,712
Spain	9,394	9,394
Sweden	14,86	14,86
Switzerland*	11,496	11,496
UK	15,241	15,241

Table 29:

- **Total number of vehicles of each type in 2050** – country-specific figures based on 2050 population assumptions [29] and projected number of cars per capita in 2050[30] – as shown in table 31.

[29] 'Migration only' or 'Growth' values used for each scenario as described in Step 1.

[30] Given the top-down approach to scenario building for the e-HIGHWAY 2050 project, specific changes in bottom-up factors that could affect the number of passenger vehicles per capita in 2050 were not taken into account – for example, this could include policy intervention, a change in the age distribution of the population, changing vehicle sizes and improvement in alternative modes of transport such as public transport.

[31] For each scenario, an initial estimate of the cars per capita figure for 2050 was made by growing current levels based on the relevant GDP growth assumptions for each Scenario as described in Step 1 and an observed (country-specific) historical rela-

- **Share of kilometres by each type of electric vehicle** – common European assumptions for each scenario as shown in Table 31: as this is a policy-driven input[32].

The proportions for x-5 and x-7 in table 31 are comparable to the electrification assumptions for passenger vehicles in the Eurelectric Power Choices scenarios [Dem-13]. The proportions for x-16 are based on projected mix of new cars in 2040 and 2050 in a report for the EC on the decarbonisation of the transport sector [Dem-14]. The proportions for x-10 and x-13 are the mid-points of the values used for the other scenarios.

Country	2010	2050
Austria	13,792	13,792
Belgium	13,456	13,456
Bosnia and Herzegovina*	11,496	11,496
Bulgaria	8,64	8,64
Croatia*	11,496	11,496
Cyprus	8,327	8,327
Czech Republic	12,677	12,677
Denmark	17,285	17,285
Estonia	11,542	11,542
Finland	14,107	14,107
France*	14,938	14,938
FYROM	11,496	11,496
Germany*	13,891	13,891
Greece*	11,496	11,496
Hungary*	8,769	8,769
Ireland*	11,496	11,496
Italy	13,518	13,518

tionships between GDP and number of cars (2003-2010). The projected 2050 cars per capita figure was then tested for two conditions – it must be no lower than the cars/capita figure for the country in 2010, and if the projected 2050 seemed unreasonably high. In the latter case, an average of the projected figure and the European average were taken. An adjustment has been made on one of these grounds to the projected 2050 cars per capita value for all countries marked with an asterisk in table 30.

32 In addition, country specific data on the penetration of electric vehicles by 2050 is not available from a single source. The EU Clean Fuels Strategy [Dem-29] gives some indication of the 'first-movers' in developing electric vehicle fleets, however this only shows projections to 2020.

Country	2010	2050
Latvia	16,467	16,467
Lithuania	14,858	14,858
Luxembourg	12,547	12,547
Montenegro	11,496	11,496
Netherlands*	14,008	14,008
Norway*	11,496	11,496
Poland	9,62	9,62
Portugal*	11,496	11,496
Romania	9,84	9,84
Serbia*	11,496	11,496
Slovakia	8,957	8,957
Slovenia	14,712	14,712
Spain	9,394	9,394
Sweden	14,86	14,86
Switzerland*	11,496	11,496
UK	15,241	15,241

Table 29: Average km travelled per passenger vehicle per year

Source: Analysis of data from DGTREN [Dem-15] and average occupancy rates from European Environment Agency

Value	Cars per capita	Cars per capita	Cars per capita	Total cars	Total cars
Scenario	**All**	**x-16**	**x-5, x-7, x-10, x-13**	**x-16**	**x-5, x-7, x-10, x-13**
Timeframe	2010[1]	**2050**	**2050**	**2050**	**2050**
Country				**Thousands**	**Thousands**
Austria	0.53	0.60	0.63	5,158	5,686
Belgium	0.49	0.61	0.65	7,638	8,494

Bosnia and Herzego-vina*	-	0.16	0.18	615	703
Bulgaria	0.35	0.45	0.47	2,55	2,8
Croatia	0.34	0.50	0.56	2,218	2,568
Cyprus*	0.42	0.46	0.47	474	512
Czech Republic*	0.43	0.46	0.47	4,684	5,059
Denmark*	0.39	0.44	0.46	2,544	2,75
Estonia*	0.41	0.45	0.47	524	566
Finland	0.54	0.61	0.65	3,316	3,7
France	0.48	0.54	0.55	37,432	40,32
FYROM*	-	0.32	0.33	650	710
Germany*	0.52	0.52	0.52	34,863	36,627
Greece*	0.50	0.50	0.51	5,494	5,902
Hungary	0.30	0.38	0.40	3,324	3,646
Ireland	-	0.52	0.58	3,097	3,583
Italy*	0.60	0.60	0.60	37,798	39,71
Latvia*	0.28	0.39	0.40	667	724
Lithuania*	0.51	0.51	0.52	1,378	1,456
Luxembourg	0.67	0.67	0.69	446	485
Montenegro*	0.26	0.26	0.26	165	173
Netherlands*	0.47	0.48	0.49	7,937	8,562
Norway*	0.47	0.48	0.50	2,931	3,161
Poland*	0.45	0.47	0.49	15,564	16,796
Portugal*	-	0.49	0.50	4,923	5,308
Romania*	0.20	0.35	0.36	6,129	6,677
Serbia	0.21	0.27	0.28	2,415	2,696
Slovakia*	0.31	0.40	0.41	2,035	2,206
Slovenia*	0.52	0.52	0.52	1,05	1,104
Spain	0.48	0.67	0.74	33,738	38,824

Sweden	0.46	0.51	0.52	5,462	5,889
Switzerland	0.52	0.59	0.60	5,197	5,621
UK	0.46	0.59	0.63	42,868	47,918

Table 30: Overall vehicle numbers in 2050

Scenario	**x-5 and x-7**	**x-10 and x-13**	**x-16**
Electrification of heating and transport (u8)	Large scale and domestic	Large scale	Domestic
Level of new use (parameter 9)	High	High	Low
% of kilometres by EVs	20%	15%	10%
% of kilometres by PHEVs	70%	55%	40%

Table 31: Share of passenger vehicle kilometres by each type of electric vehicle (2050)

Conversion efficiency of EVs and PHEVs

It is assumed that on average the electric passenger vehicles use 0.2kWh per km travelled (as a single assumption across Europe). This conversion efficiency is based on the reported technical characteristics of the current generation of electric vehicles, for example such as the Nissan Leaf [Dem-30] and Chevrolet Volt [Dem-44].

Expected improvements in the conversion efficiency of electric passenger vehicles by 2050 are captured by the energy efficiency assumptions made in Step 3.

<u>Freight vehicles</u>

According the general approach for Step 2, there are two key components in the projection of 2050 electricity demand from each type of electric passenger vehicles in each scenario:

- estimation of end-use energy demand met by electric road freight vehicles by country in each scenario (i.e. tons kilometres travelled by electric road freight vehicles); and
- conversion efficiency, which is assumed to be the same for all countries and in all scenarios (i.e. kWh used per tons km).

<u>Tons kilometres travelled by electric freight vehicles</u>

The projected tons kilometres travelled by electric road freight vehicles for each country in each scenario are based on:

- **Tonne kilometres by road freight vehicles in 2050** – the current European figure for tonne km was uplifted by GDP growth[33]. The European figure was then split between countries based on current national haulage figures[34][35] (adjusted for GDP growth assumptions).
- **Share of road freight tonne kilometres by vehicle type –** as shown in table 32 which is based on current European split reported by Eurostat [Dem-33][36] using weight definitions from the UKERC [Dem-32][37]. Table 32 highlights that vans account for a very small share of energy demand for road freight (and hence will not represent a key differentiating factor between scenarios).
- **Share of tonne kilometres by electric vehicles for each type of road freight vehicle** – common European assumptions for each scenario as shown in table 33 as this is a policy-driven input[38].

The figures for x-5 and x-7 are based on the estimated share of new vehicles in 2030 and 2050 (from the transport decarbonisation report for the EC [Dem-14]) and the age profile of freight vehicles (based on current profile as set out in Eurostat Transport [Dem-33].

The figures for x-10 and x-13 designed to capture possible upside and the figures for x-16 designed to capture possible downside around the 'central' assumptions for x-5 and x-7.

	Share of tonne km by vehicle type
Vans/light trucks	1%
Medium trucks	38%
Heavy trucks	61%

33 This was done using the GDP values from Step 1, and the estimated relationship between tonne km and GDP based on the EC Roadmap Reference scenario [Dem-3].Total European level freight tonne kilometres were slightly revised between versions one and two of this note to reflect changes in freight from Spain, FYROM, Bosnia and Herzegovina, Serbia and Montenegro.

34 Based on the European Commission's Mobility and Transport dataset [Dem-31]

35 One of the challenges for estimating the electricity demand from road freight is the high level of travel by freight outside its home country ('international haulage'). For example, Polish freight vehicles are estimated to drive significant distances outside Poland (and therefore may not use the Polish network to charge their vehicles). Given the available data, the approach of splitting the European figure for international haulage between countries based on the split of national haulage (i.e. freight travel within home country) was taken.

36 Not all the countries covered in the e-highway 2050 project are within the scope of Eurostat's data collection. These include: Bosnia and Herzegovina, Serbia, Montenegro, and FYROM. As such, the 2050 freight demands of these countries have been set at the demands of countries with similar population and electricity demand. These countries are: Slovenia, Bulgaria, Estonia and Slovenia respectively.

37 UK ERC was the source for the EC projections for electric vehicle penetrations in road freight in 2050 [Dem-14]

38 In addition, country specific data on the penetration of electric vehicles by 2050 is not available from a single source. The EU Clean Fuels Strategy [Dem-29] gives some indication of the 'first-movers' in developing electric vehicle fleets, however this only shows projections to 2020.

Table 32: Share of tonne kilometres by each type of road freight vehicles (2050) Source: Eurostat [Dem-33]

	Scenario	x-5 and x-7	x-10 and x-13	x-16
	Electrification of heating and transport (u8)	**Large scale and domestic**	**Large scale**	**Domestic**
	Level of new use (parameter 9)	**High**	**High**	**Low**
Vans/light trucks	% of tonne km by EVs	20%	25%	10%
	% of tonne km by PHEVs	40%	50%	20%
Medium trucks	% of tonne km by EVs	20%	25%	10%
	% of tonne km by PHEVs	30%	37.5%	15%
Heavy trucks	% of tonne km by EVs	0%	0%	0%
	% of tonne km by PHEVs	0%	0%	0%

Table 33: Share of tonne kilometres by electric vehicles for each type of toad freight vehicles (2050) - based on EC [Dem-14]

Conversion efficiency by electric freight vehicles

There is currently little data available on the conversion efficiency of the batteries in electric road freight vehicles. As an average car is approximately one tonne, it is assumed that the same conversion efficiency assumed for cars (in terms of kWh per km) could be used for kWh per tonne km of freight. Therefore, it is assumed that on average the electric road freight vehicles use 0.2kWh per tonne km travelled (as a single assumption across Europe). This approach is supported by the fact that current figures suggest a similar ratio of energy per tonne km as for energy per passenger vehicle km[39].

Expected improvements in the conversion efficiency of electric road freight vehicles by 2050 are captured by the energy efficiency assumptions made in Step 3.

Electrification of heat

Heat demand within Europe is widely acknowledged as an important source of carbon emissions which would need to be abated in order to meet GHG targets. This abatement can occur through two channels:

- reducing the demand for heat through energy efficiency measures (covered under Step 3); and

[39] Current energy demand and (tonne) km figures for European countries can be found in DG TREN [Dem-15]. Passenger km can be converted into km travelled by applying an assumed occupancy rate, such as the European average of 1.6 passengers per car (based on EEA [Dem-17]).

- Electrification of heat to take advantage of high conversion efficiencies and low- carbon power generation (covered by this Step).

As per our general approach for Step 2, there are two key components in our projection of

2050 electricity demand from additional heat in each scenario:

- estimation of **additional** end-use energy demand met by electricity by country in each scenario (i.e. **additional** electrification of heat from current levels); and
- conversion efficiency, which is assumed to be the same for all countries and in all scenarios (i.e. kWh of electricity required to produce a kWh of heat).

In public studies on decarbonisation in Europe, lower electrification scenarios are also seen that can meet GHG targets, mostly through high application of district heating[40]. For example, Euroheat's European level study which focuses on "the role of low temperature district heating in the future EU27 energy system" project that heating in the EU from electricity could be as low as 10% [Dem-42].

Heat demand in three sectors is considered – residential, commercial and industrial – which we map onto the terms used for the electrification[41] uncertainty as follows:

- large scale – industry and commercial; and
- residential – residential (e.g. houses using heat pumps or direct electric heating as a means to heat water or directly heat rooms).

Unlike the transport sector, there is comparable scope for electrification of heating through either large scale or residential approaches.

Additional electrification of heat from current levels

The scope for the electrification of heat demand varies significantly between European countries, because of differences in both final heat demand (per capita[42]) and in the proportion that is currently electrified.

A country-specific approach estimating the heat demand that is not currently electrified is taken into account[43]. This is combined with top-down European assumptions for the proportion of this demand that is

[40] For example, Element Energy and AEA's [Dem-22] 'District Heating Constrained' scenario with only 46% of heat electrified, all through heat pumps.

[41] When referring to electric vehicles in this note, vehicles that draw electricity from the grid are meant. Therefore, this does not include fuel cell electric vehicles or hybrid vehicles that use electricity generated by braking.

[42] For example, national variations can be driven by differences such as GDP/capita levels, temperature patterns, and energy efficiency of existing building stock.

[43] This avoids having to directly estimate the current share of electricity in heat production (which was taken into account implicitly in the projections of Step 1). This is estimated to be approximately12% at a European level [Dem-42], with major differences between countries where data is available (which is not the case on a consistent basis across Europe). For example 46% of residential heat in Spain comes from electricity [Dem-35] compared to 7% in the UK [Dem-36]. In France, 70% of newly built homes between 2006 and 2009 had electric heating [Dem-38].

electrified in each scenario. This therefore produces country level estimates for the amount of additional heat that is electrified by 2050 (based on top-down assumptions driven by European policy).

Therefore, additional electrification of heat from current levels for each country in each scenario is based on:

- **Estimated heat demand by sector in 2050 that is not currently electrified –** Current levels by country are based on IEA data [Dem-38 – Dem-41] on fuel consumption (excluding electricity and transport[44]) for three sectors – residential, commercial and industrial[45]. This data for 2010 can be seen in table 34. The residential and commercial demand increases in line with population growth in the scenario (i.e. 'Migration only' or 'Growth'), whilst industrial demand grows with GDP in the scenario (i.e. 'High' or 'Low')[46].
- **Percentage additional electrification of heat by sector by 2050 –** this is based on top-down European assumptions in line with policy goals as shown in table 35 There is not a single source for these assumptions which are based on judgement drawn from the review of a number of different European and national studies. It has been proven to be very challenging to gather consistent figures across Europe for the scope for the additional electrification of heating across sectors. This is supported by Euroheat's statement in their study of European district heating [Dem-42], the heating sector has "largely been overlooked in all scenarios exploring the energy futures towards 2050" and that even the EU Energy Roadmap [Dem-7] "omits a thorough analysis of the heating and cooling sector" [Dem-42]. Although there are some national studies – e.g. for the UK, there are studies by National Grid [Dem-23] and by Element Energy and AEA [Dem-22], studies in different countries use different methodologies and assumptions. Projections of the proportion that new heating could be electrified have been developed using all these studies.

Sector	Residential	Commercial	Industrial	Total
Overall European figure	2828	979	2225	**6032**
Austria	62	20	61	**144**
Belgium	84	36	84	**204**
Bosnia and Herzegovina	4	0	2	**7**
Bulgaria	14	3	20	**38**

44 The 'heat' numbers will therefore also include some other processes such as cooking at the residential level (e.g. 3% of residential heat demand in the UK [Dem-36]) and processes at the industrial level.

45 The sectorial approach allows us to vary the degree of electrification by sector if required.

46 This is based on an estimated relationship of a 20% increase in industrial heat per 100% increase in GDP, based on analysis of the DGTREN Reference scenario (2010-2030) [15]).

Sector	Residential	Commercial	Industrial	Total
Croatia	15	3	13	**31**
Cyprus	2	0	2	**5**
Czech Republic	62	22	69	**153**
Denmark	47	14	20	**80**
Estonia	10	2	4	**17**
Finland	43	5	87	**135**
France	350	127	224	**700**
FYROM	3	1	3	**8**
Germany	580	237	416	**1233**
Greece	36	5	26	**67**
Hungary	56	25	21	**101**
Ireland	28	10	15	**54**
Italy	295	111	221	**627**
Latvia	16	4	6	**26**
Lithuania	13	4	7	**24**
Luxembourg	5	3	5	**13**
Montenegro	1	0	2	**4**
Netherlands	109	78	114	**301**
Norway	12	6	25	**43**
Poland	216	56	128	**400**
Portugal	19	8	46	**72**
Romania	82	14	52	**148**
Serbia	14	4	19	**36**
Slovakia	22	16	27	**65**
Slovenia	12	3	9	**24**
Spain	114	30	182	**325**
Sweden	47	25	86	**159**
Switzerland	57	25	27	**108**

Sector	Residential	Commercial	Industrial	Total
UK	400	77	203	**680**

Table 34: Country specific estimated heat demand in 2010 by sector (excluding demand currently met by electricity) (TWh of heat demand) - Source: IEA

Scenario	**x-5 and x-7**	**x-10 and x-13**	**x-16**
Electrification of heating and transport (u8)	Large scale and domestic	Large scale	Domestic
Level of new use (parameter 9)	High	High	Low
Residential	40%	60%	20%
Commercial	60%	40%	20%
Industrial (heat)	60%	40%	20%
Industrial (processes)	10%	10%	10%

Table 35: Electrification of heat not currently electrified (2050, %)

<u>Conversion efficiency of electric heating technologies</u>

The conversion efficiency varies by heating technologies (e.g. between heat pumps and direct resistive heating), and therefore, the overall conversion efficiency will depend on the assumed mix of heating technologies (which we have assumed to be 70% heat pump and 30% direct resistive heating across scenarios).

In line with the top-down approach to scenario development, the same mix across Europe is assumed – this is based on country level studies[47] in the absence of consistent European studies[48] (although this gap may be filled by the technology research being undertaken in WP3).

A coefficient of performance for direct heating of 1, and an average coefficient of performance (COP) for heat pumps of 3 was used[49]. The heat pump figure is between the figure of 2.75 suggested by AEA and NERA [Dem-45] and the upper boundary of 4 proposed by [Dem-46].

Expected improvements in the COP of heat pumps by 2050 are captured by the energy efficiency assumptions made in Step 3.

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[47] For example, 2050 heat scenarios for the UK [22] show a range of scenarios for the relative proportions of direct heating to heat pumps (which are not differentiated by sector) – measured in terms of heat output rather than electricity input.

[48] For example, while Euroheat [42] discusses the use of heat pumps in 2050, this is primarily in relation to the proportion of district heating that could come from heat pumps (approximately 12% if district heating provides 50% of heat demand).

[49] Although industrial heat pumps are expected to have higher coefficients of performance [45], a robust enough body of evidence to support the quantification of this improvement could not be found – therefore, the same COP for heat pumps across all sectors was assumed.

Summary of electricity demand from new heating uses in 2050

Table 36 shows the projected electricity demand from new heat uses in each scenario in 2050 – these values do not include the impact of network losses and energy efficiency.

Scenario Number	**x-5**	**x-7**	**x-10**	**x-13**	**x-16**
Scenario Name	**Large Scale RES and no emissions**	**100% RES**	**Big and Market**	**Big Nuclear and CCS**	**Small and Local**
Overall European figure	**5369**	**4385**	**4387**	**4854**	**3161**
Austria	19	32	9	93	60
Belgium	35	51	15	134	88
Bosnia and Herzegovina	0	2	0	14	10
Bulgaria	5	7	3	37	26
Croatia	3	7	2	26	17
Cyprus	1	1	0	12	8
Czech Republic	22	33	10	78	53
Denmark	11	22	5	43	29
Estonia	2	4	1	14	9
Finland	14	25	8	92	66
France	105	180	46	727	479
FYROM	1	2	1	10	7
Germany	160	245	71	731	466
Greece	6	15	3	74	51
Hungary	15	23	6	66	42
Ireland	10	17	4	46	29
Italy	93	151	41	583	364
Latvia	4	6	2	30	20
Lithuania	4	6	2	41	28

Luxembourg	3	4	1	8	5
Montenegro	0	1	0	4	3
Netherlands	58	66	25	189	118
Norway	8	9	4	123	92
Poland	44	86	20	177	114
Portugal	10	12	5	83	51
Romania	16	33	8	71	46
Serbia	4	7	2	36	25
Slovakia	12	13	5	31	20
Slovenia	3	5	1	16	11
Spain	42	68	20	586	363
Sweden	28	34	13	140	99
Switzerland	20	31	8	107	70
UK	78	200	35	430	292

Table 36: Projections for final electricity demand from new heat uses by country

Political, socio-political and environmental criteria

The relevant political, socio-political and environmental criteria for the projection of end- use electricity demand projections are:

- **Option** – increase of energy efficiency (High/Medium/Low).

The other uncertainties, options and assumptions relate to international relations, public perception towards generation technologies, imports of fuel and electricity, and GHG emissions target[50] relate to fuel and carbon allowance prices, which were not used to project annual electricity demand levels.

Energy efficiency

In calculating the annual level of final electricity demand (including network losses), it was assumed that ‘energy efficiency’ refers to Passive Demand Side technologies – e.g. insulation in buildings or new components that consume less (new fridges etc.). Active demand side technologies are considered in the scope for changing the hourly time series of demand, which is not in the scope of this particular note.

[50] A reduction of 80-95% in GHG emissions compared to 1990 is a fixed assumption across all scenarios.

Step 3 considers only the incremental improvements in energy efficiency from current levels as historical developments in energy efficiency are accounted for in the projection of demand based on GDP growth (Step 1). Table 37 summarises the assumed improvement in energy efficiency across Europe in each scenario. **Each country is assumed to have put equal weight on energy efficiency improvements,** and therefore, the values in table 36 apply equally for all countries in each scenario.

Scenario number	x-5	x-7	x-10	x-13	x-16
Scenario name	Large scale RES & no emissions	100% RES"	Big & Market	Big Nuclear and CCS	Small and Local"
Energy efficiency level	Low	High	Medium	Low	High
Annual improvement in energy efficiency (2010-2050)	1.0%/a	1.5%/a	1.25%/a	1.0%/a	1.5%/a
Total reduction in electricity demand in 2050	33%	45%	40%	33%	45%

Table 37: Energy efficiency projections

The high value is consistent with the requirements for annual new energy savings out to 2020 in the Energy Efficiency Directive. It recognises the fact that it will be increasingly difficult to continue at the same rate of energy efficiency savings (as the easiest actions are likely to be taken first). Therefore, it seems prudent to set the High value in line with current targets for the short-term, even if this is below the maximum boundary of 3%/a proposed in [Dem-2][51].

The Low value is set at 1% as it is expected that some improvements in energy efficiency will be needed to meet the overall GHG targets and therefore, the Low value is above the minimum boundary of 0%/a proposed in [Dem-1].

As part of the research undertaken to arrive at these figures, the existing material on potential improvements in energy efficiency (as listed in the References in Section 7) were reviewed. However, this information was generally not consistent with the top-down approach required for the e-Highway 2050 scenarios for a combination of the following reasons:

- Country-specific studies (so not consistent on European basis);
- Very detailed estimates focused specific sub-sectors and/or actions; and
- Short-term outlook (i.e. out to 2020).

[51] The boundary conditions for energy efficiency are actually set out in the discussion of the economic and financial criteria in [Dem-2].

However, these studies did not provide any information that would contradict the proposed top-down values

Sensitivity

Table 38 shows the results of sensitivity on energy efficiency levels – whereby the impact of using each of the three energy efficiency levels (High, Medium, Low) in each main scenario was tested.

Scenario number		x-5	x-7	x-10	x-13	x-16
Scenario name		Large scale RES & no emissions	100% RES"	Big & Market	Big Nuc and CCS	Small and Local"
Annual Energy Efficiency improvement in Main Scenario		1% (Low)	1.5% (High)	1.25% (Medium)	1% (Low)	1.5% (High)
Main scenarios	**Final electricity demand (including network losses)**	**5364**	**4381**	**4387**	**4854**	**3161**
Impact of energy efficiency being 1% a year	Final electricity demand (including network losses)	5364	5364	4854	4854	3871
Impact of energy efficiency being 1.25% a year	Final electricity demand (including network losses)	4848	4848	4387	4387	3498
Impact of energy efficiency being 1.5% a year	Final electricity demand (including network losses)	4381	4381	3964	3964	3161

Table 38: Final electricity demand (including network losses) in sensitivity on energy efficiency improvements

Network losses

The final step in the process takes account for the impact of network losses on the level of generation required to meet electricity demand within a country. As these losses primarily occur on the lower voltage distribution networks, they will not be captured by the topography analysis in WP2.3. Therefore, a top-down estimate for each country based on the current rate of network losses (as reported by the IEA [Dem-41]) was used.

There is currently a wide range of network loss percentages[52] across Europe – this reflects the fact that the network losses include both technical losses and non-technical losses. There is also uncertainty about how network losses will evolve out to 2050, given changing generation and consumption patterns. For example, eHighway2050 Deliverable D1.1 [Dem-45] reports that TSOs have mixed views about whether network losses will increase or decrease out to 2050. Due to the relative topological and infrastructure differences between **countries that will remain to an extent** in 2050, it is infeasible to presume that country loss percentages will converge onto a single value in Europe in 2050. Instead, it can be expected that the variation between countries will remain, albeit reduced as countries with very high losses invest in improved transmission networks.

Table 39 shows the assumed network loss rates by country in all scenarios in 2050. In producing the annual demand, the following was assumed (across all scenarios):

- For countries with network loss rate above the European average in 2010, the network loss rate for 2050 falls to the 2010 European straight-line average of 8.3% (through sharing of best practice etc.) – these countries are highlighted in yellow in table 39; and
- For countries with network loss rate below the European average in 2010, the network loss rate in 2050 remains at the 2010 level for that country.

The data shown for 2010 values of network losses has been verified by two independent data providers (Eurostat and the International Energy Agency). In general, these two providers agreed on the level of losses present in each country. As such, for consistency, the network losses in 2010 are set as those for the IEA[53].

Data	2010	2050 (all scenarios)
Overall European figure	6.8%	6.4%
Austria	5.1%	5.1%
Belgium	4.7%	4.7%
Bosnia and Herzegovina	13.0%	8.3%
Bulgaria	13.6%	8.3%
Croatia	11.1%	8.3%
Cyprus	4.3%	4.3%
Czech Republic	7.0%	7.0%

[52] The mix between distribution connected generation and transmission connected generation could affect the rate of network losses in a cluster. However, estimating this impact is probably not consistent with the top-down approach taken to scenario-building in the e- HIGHWAY 2050 project.

[53] Except Spain, which has a far higher network loss according to Eurostat. This higher network loss was used based on experience gained within the extensive modelling of the Spanish electricity market.

Data	2010	2050 (all scenarios)
Denmark	7.2%	7.2%
Estonia	12.3%	8.3%
Finland	3.2%	3.2%
France	7.0%	7.0%
FYROM	15.5%	8.3%
Germany	4.2%	4.2%
Greece	6.4%	6.4%
Hungary	9.5%	8.3%
Ireland	7.7%	7.7%
Italy	6.2%	6.2%
Latvia	10.4%	8.3%
Lithuania	9.6%	8.3%
Luxembourg	1.8%	1.8%
Montenegro	16.6%	8.3%
Netherlands	3.8%	3.8%
Norway	6.9%	6.9%
Poland	8.4%	8.3%
Portugal	7.8%	7.8%
Romania	13.3%	8.3%
Serbia	15.7%	8.3%
Slovakia	3.3%	3.3%
Slovenia	7.3%	7.3%
Spain	9.3%	8.3%
Sweden	7.3%	7.3%
Switzerland	6.8%	6.8%
UK	7.4%	7.4%

Table 39: Network losses (as % of sum of final demand and network losses) - Source: IEA [Dem-41] and Eurostat [Dem-49]

Summary

The methodology, assumptions, sources and reference material for each of the four steps in projecting the final electricity demand (including network losses) for the 5 main e-Highway2050 scenarios were described in detail.

The results of the four step process are summarised in the following:

- Table 40 sets out the final electricity demand (including network losses) at European level for each scenario, and shows the contribution of each Step in the process to the final number.
- Table 41 shows the final electricity demand (including network losses) for each country in each scenario.
- Tables 40 and 41 show the final electricity demand (including network losses) for each scenario (at a European level) compared to other well-known studies. As can be seen, the scenarios clearly encompass the other studies' values, showing that the e-Highways scenarios have a wide enough range to comprehensively test possible power systems in 2050.
- Supporting Excel file shows the contribution of each Step in the process to the final electricity demand (including network losses) for each country.

	Scenario number	x-5	x-7	x-10	x-13	x-16
	Scenario name	Large scale RES & no emissions	100% RES	Big & Market	Big Nuclear and CCS	Small and Local
Calculation step and Criteria	**Demand parameters**					
Step 1: Economic and Financial	Population (demographic changes); GDP increase	5201	5201	5201	5201	4612
Step 2: Technology	New use	2297	2297	1584	1584	798
Step 3: Political, socio-political and environmental	Energy efficiency	-2482	-3402	-2683	-2246	-2454
Step 4: Network losses	n/a	349	285	285	315	205
Final (= sum of all four steps)	**Final electricity demand (including network losses)**	**5364**	**4381**	**4387**	**4854**	**3161**

Table 40: European projections for electricity demand by Step (2050, TWh)

Scenario Number	**x-5**	**x-7**	**x-10**	**x-13**	**x-16**
Scenario Name	Large Scale RES and no emissions	100% RES	Big and Market	Big Nuclear and CCS	Small and Local
Overall European figure	**5369**	**4385**	**4387**	**4854**	**3161**
Austria	104	85	84	93	60

Belgium	148	121	121	134	88
Bosnia and Herzegovina	16	13	13	14	10
Bulgaria	39	32	34	37	26
Croatia	29	24	24	26	17
Cyprus	13	10	11	12	8
Czech Republic	88	72	71	78	53
Denmark	52	43	39	43	29
Estonia	15	12	12	14	9
Finland	101	83	84	92	66
France	795	649	657	727	479
FYROM	10	8	9	10	7
Germany	820	669	661	731	466
Greece	83	68	67	74	51
Hungary	73	59	60	66	42
Ireland	53	43	42	46	29
Italy	639	522	527	583	364
Latvia	32	26	27	30	20
Lithuania	43	35	37	41	28
Luxembourg	9	7	8	8	5
Montenegro	4	3	3	4	3
Netherlands	197	161	170	189	118
Norway	125	102	112	123	92
Poland	211	172	160	177	114
Portugal	87	71	75	83	51
Romania	84	68	64	71	46
Serbia	38	31	32	36	25
Slovakia	33	27	28	31	20
Slovenia	18	15	14	16	11
Spain	610	498	529	586	363

Sweden	146	120	127	140	99
Switzerland	117	95	97	107	70
UK	538	439	389	430	292

Table 41: Projections for final electricity demand (including network losses) by country (2050, TWh)

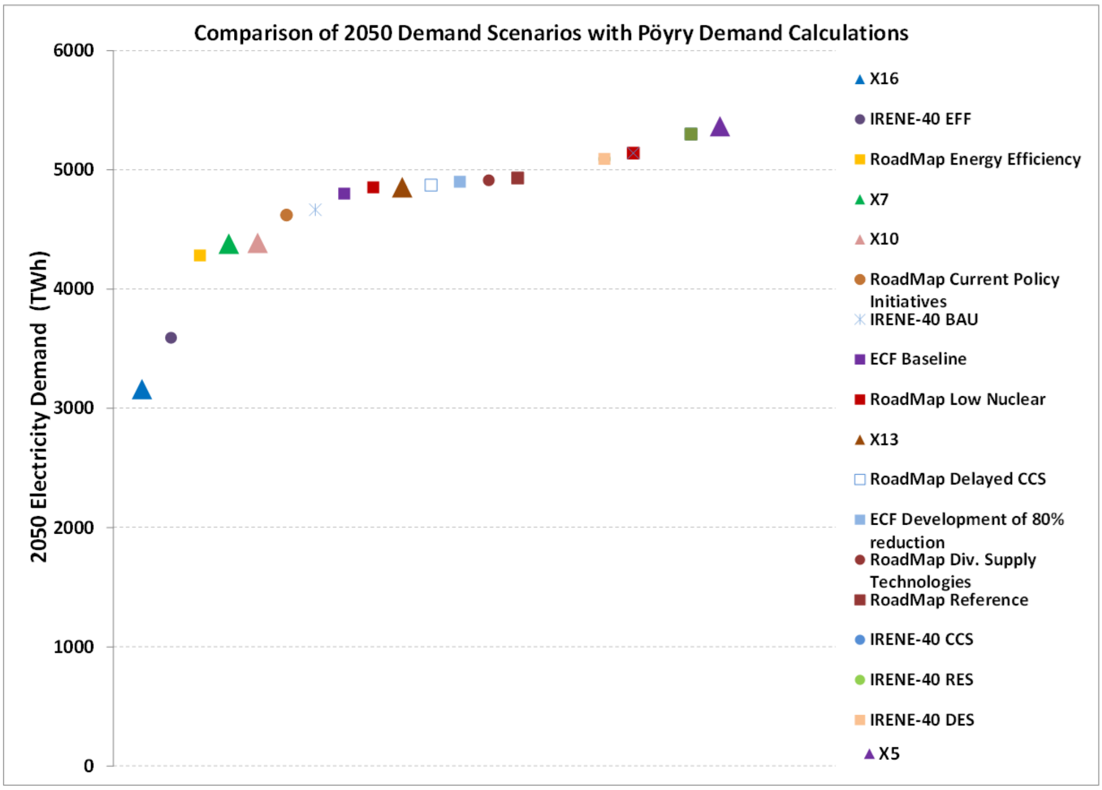

Figure 35: Comparison of e-Highway 2050 electricity demand scenarios (including network losses) against external studies

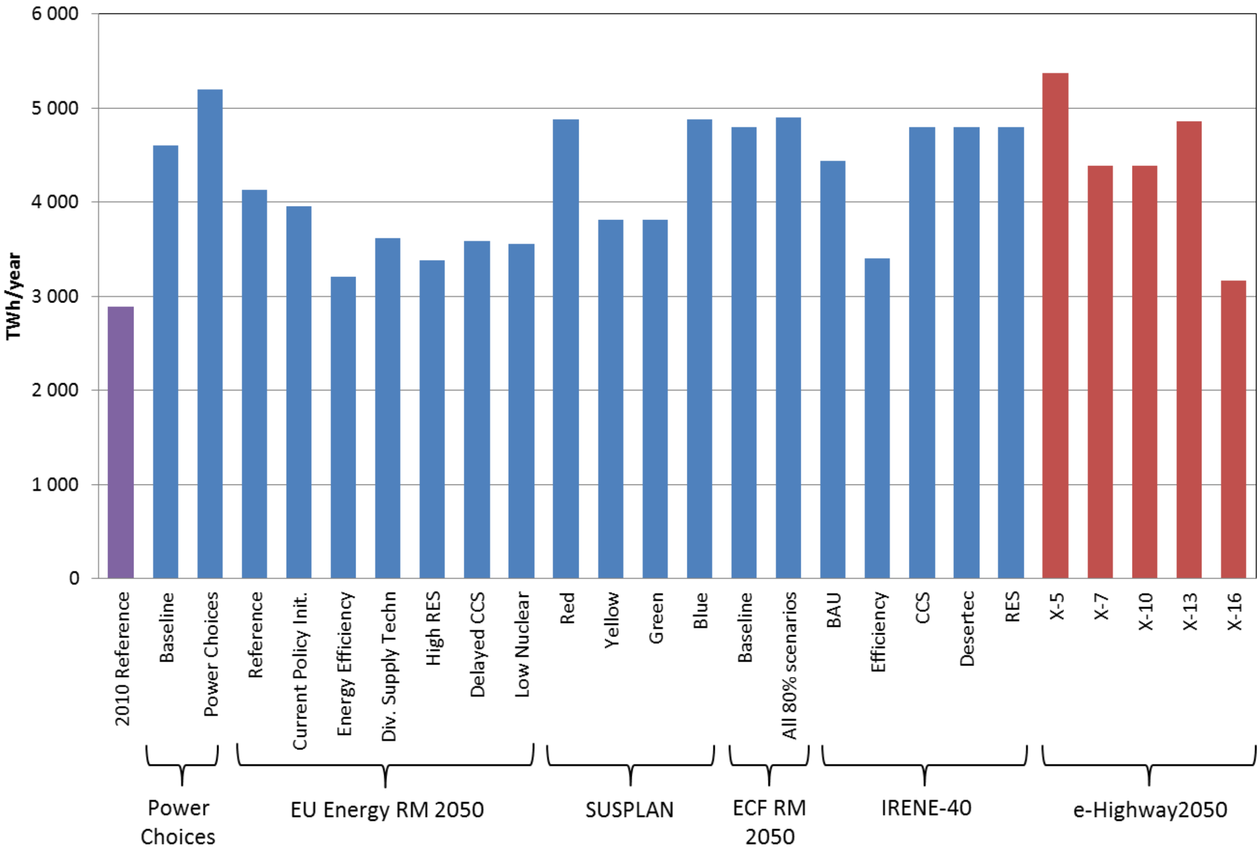

Figure 36: Comparison of e-Highway 2050 EU demand values with previous EU project estimates

Annex D: Calculation of the demand time series

Input data and data sources

Research has been done on how to capture the impact of structural changes in electricity demand on the demand time series used in the modelling for the e-Highway2050 project. The data was prepared in the way to be used as an input for the 2050 Load Calculation Tool. Total annual energy consumption values for all of the analysed new uses of electricity as well as for current electricity use for 2050 (except DSM potential) were calculated. This data is presented in table 42. In figure 37 and figure 38 structures of electricity uses in 2050 is shown for all of the countries and two selected scenarios.

The document: “GUIDELINES FOR CONSTRUCTING VISIONS 1 & 3. ADDITIONAL PARAMETERS FOR VISION 1 & 3 THAT ALLOWS ENTSO-E PAN EU MARKET STUDY TEAM TO CONSTRUCT VISIONS 2 & 4” prepared by ENTSO-E System Development Committee was used as a source of inspiration and data source as well.

Prepared 2050 Load Calculation Tool, was in concept similar to Load Vision model used by ENTSO-E, however developed methodology differs highly due to more detailed and complex approach.

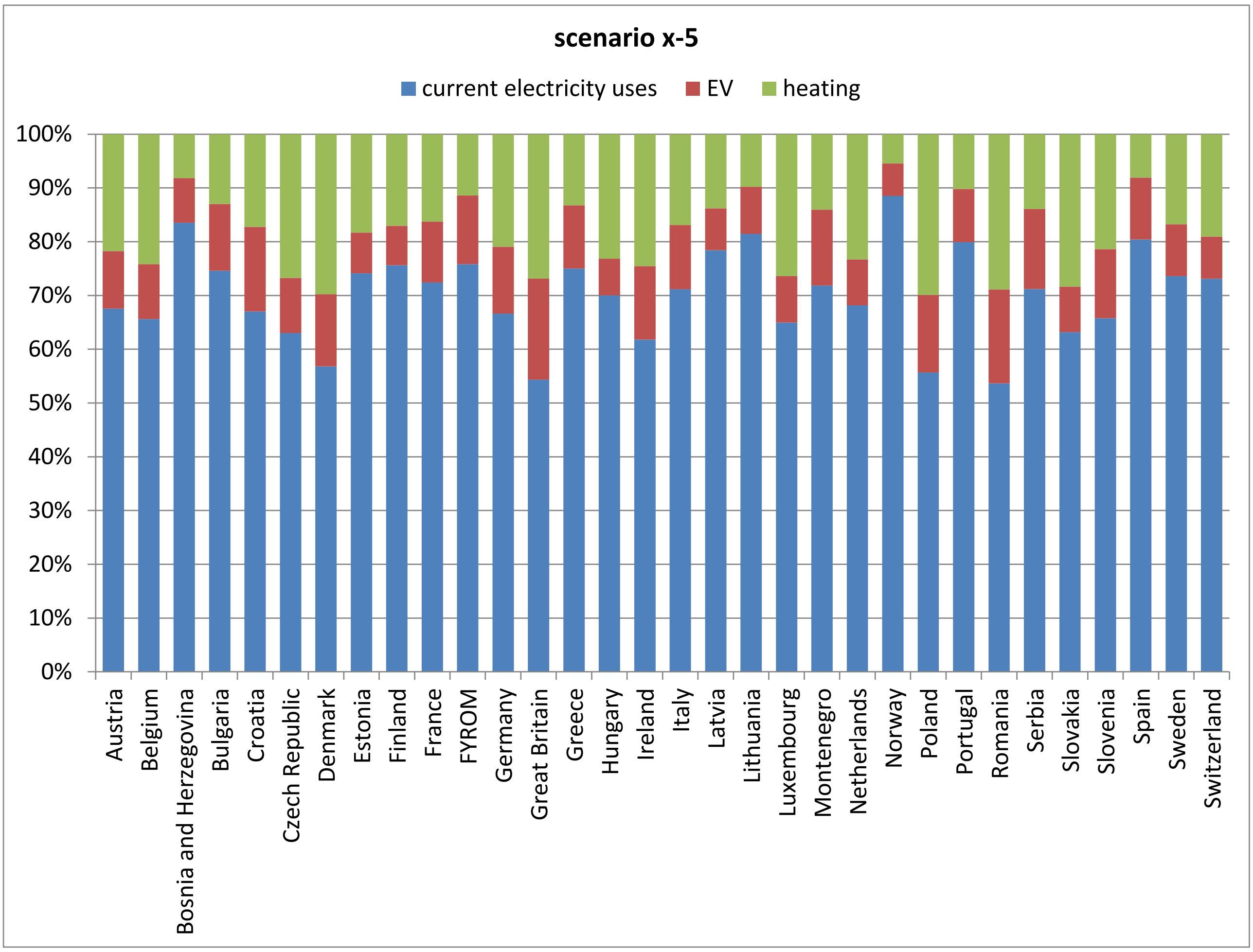

Figure 37: Structure of electricity uses in 2050 for scenario x-5.

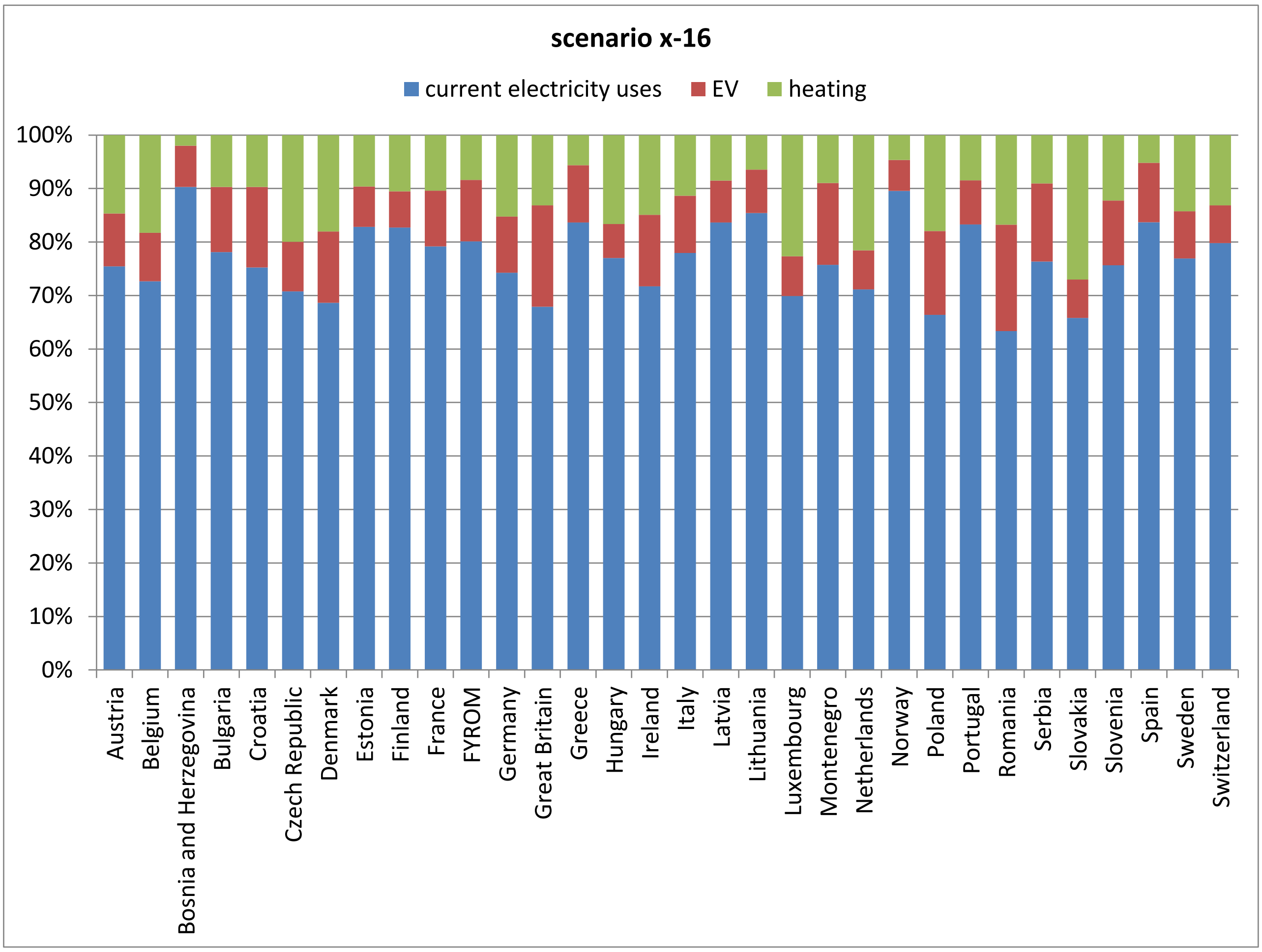

Figure 38: Structure of electricity uses in 2050 for scenario x-16

	x-5				**x-7**				**x-10**				**x-13**				**x-16**			
	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating
Austria	70	11	15	8	57	9	12	6	63	8	3	9	70	9	3	10	51	4	1	4
Belgium	97	15	23	13	80	12	19	11	88	11	6	16	97	12	7	18	73	6	3	6
Bosnia and Herzegovina	13	1	1	0	11	1	1	0	12	1	0	0	13	1	0	0	9	0	0	0
Bulgaria	29	5	3	2	24	4	2	2	26	4	0	3	29	5	0	3	23	2	0	1
Croatia	20	5	4	1	16	4	3	1	18	4	0	2	20	4	1	2	14	2	0	1
Czech Republic	55	9	14	9	45	7	12	7	50	7	3	11	55	7	3	12	43	4	1	5
Denmark	30	7	12	4	24	6	10	3	27	5	2	5	30	6	2	5	23	3	1	2
Estonia	11	1	2	1	9	1	2	1	10	1	0	1	11	1	0	1	8	0	0	0
Finland	76	7	10	7	62	6	8	6	69	6	1	8	76	6	1	9	59	3	0	4
France	576	90	91	39	470	73	74	31	520	68	20	48	576	76	22	54	416	37	9	18

	x-5				**x-7**				**x-10**				**x-13**				**x-16**			
	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating
FYROM	8	1	1	0	6	1	1	0	7	1	0	1	8	1	0	1	6	1	0	0
Germany	543	101	112	59	443	83	92	48	491	69	28	73	543	77	31	81	392	34	12	28
Great Britain	284	98	111	30	232	80	90	24	257	72	13	37	284	79	14	41	224	40	6	15
Greece	62	10	8	3	51	8	7	2	56	7	1	3	62	8	1	3	45	4	0	1
Hungary	51	5	12	5	41	4	10	4	46	4	3	7	51	4	4	7	37	2	1	2
Ireland	42	9	12	4	34	8	10	3	38	7	2	5	42	8	3	6	31	4	1	2
Italy	455	76	74	34	371	62	60	28	411	57	17	43	455	63	19	48	308	32	7	16
Latvia	25	2	3	2	21	2	2	1	23	2	0	2	25	2	1	2	18	1	0	1
Lithuania	35	4	3	2	29	3	2	1	32	3	0	2	35	3	1	2	25	1	0	1
Luxembourg	6	1	1	1	5	1	1	1	5	1	1	1	6	1	1	1	4	0	0	0
Montenegro	3	1	0	0	2	0	0	0	3	1	0	0	3	1	0	0	2	0	0	0

	x-5				**x-7**				**x-10**				**x-13**				**x-16**			
	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating	Current electricity use	EV	Residential heating	Non-residential heating
Netherlands	134	17	25	20	110	14	21	17	121	12	11	26	134	14	12	28	97	7	5	9
Norway	111	8	4	3	90	6	3	3	100	6	1	4	111	7	1	4	87	3	0	2
Poland	117	30	46	17	96	25	37	14	106	25	7	22	117	28	8	24	91	12	3	9
Portugal	69	9	4	4	57	7	4	4	63	6	1	5	69	7	1	6	45	4	0	2
Romania	45	15	16	8	37	12	13	6	41	13	2	9	45	14	2	10	36	5	1	4
Serbia	27	6	3	2	22	5	3	2	25	5	1	2	27	5	1	3	22	2	0	1
Slovakia	21	3	5	4	17	2	4	4	19	2	2	5	21	2	2	6	16	1	1	2
Slovenia	12	2	3	1	10	2	2	1	11	2	0	1	12	2	0	2	9	1	0	1
Spain	490	70	30	19	400	57	25	16	443	59	5	23	490	65	5	25	326	25	2	10
Sweden	108	14	13	11	88	12	11	9	97	11	4	14	108	12	5	15	86	6	2	6
Switzerland	85	9	16	7	70	7	13	5	77	7	4	9	85	8	5	9	62	4	2	3

Table 42: Total annual energy consumption values [TWh] for all of the analysed new uses of electricity for 2050 in analysed scenarios

Methodology

The starting point for the 2050 time series for each country (across all 5 scenarios) are the **historical hourly demand profiles**. This historical data is provided by ENTSO-E and comes from **2010, 2011** and **2012**. Obtained data is normalized separately for each historical year and country to match total energy consumption for current uses of electricity given by POYRY. This process is described in the next paragraph. This fundamental demand profile for 2050 is increased by additional values resulting from new sources of demand, like **electric vehicles** – described in following paragraphs and **heating** – also described beneath described. The flow chart of the whole process is presented in figure 39.

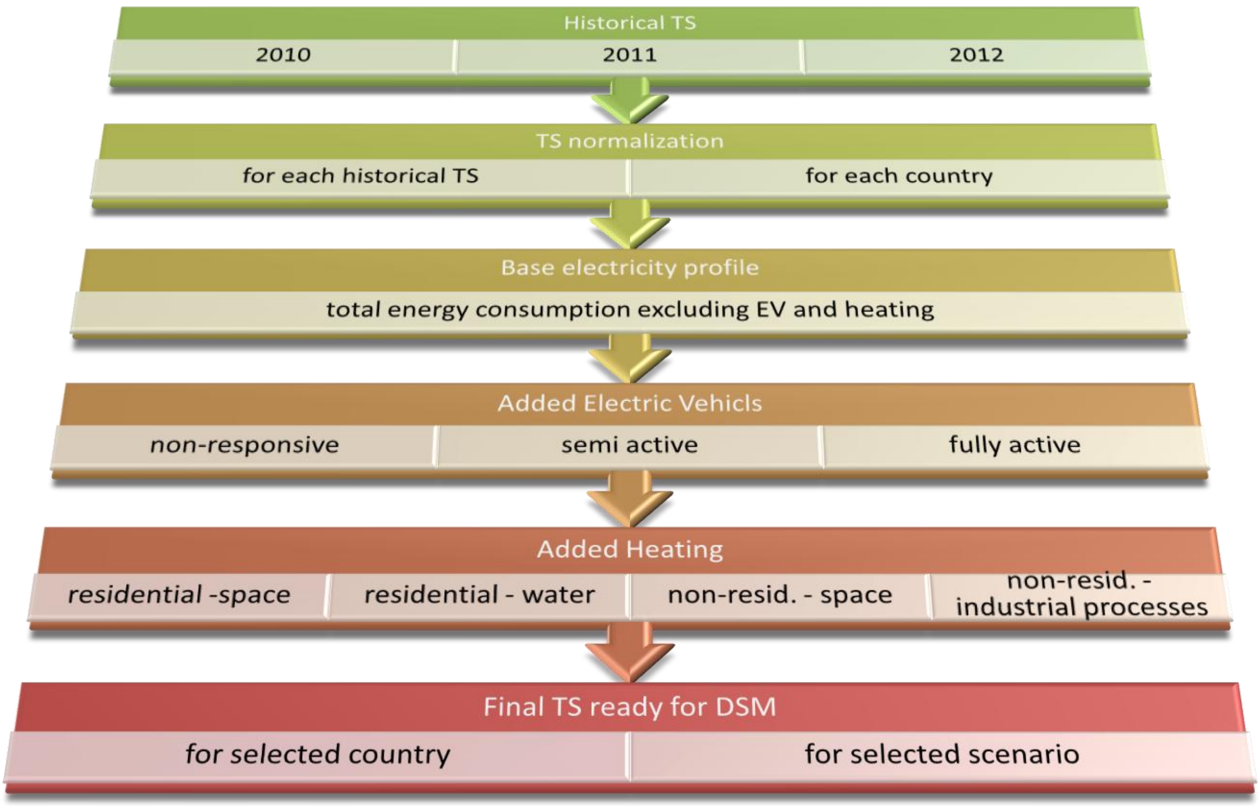

Figure 39: Demand TS for 2050 – methodology flow chart

Normalisation and TS creation for 2050

Time series for each country for historical years (2010, 2011, and 2012) was normalized according to the following equation:

$$\forall_{TS\,year}\ \forall_{country}\ \ C_i = \frac{P_i}{\sum_{i=1}^{8760} P_i}$$

Where:

C_i – contribution factor of each hour in total yearly consumption for a given TS,

i – hour in yearly TS,

P_i – power recorded in *i* hour.

Regarding total yearly consumption of each country in 2050, it is recommended to calculate new values for 2050 TS.

$$\forall_{scenario}\ \forall_{TS\,year}\ \forall_{country}\ \ P_i = C_i * E_{Tot} * 1000$$

Where:

P_i – power recorded in *i* hour, [GW]

C_i – contribution factor of each hour in total yearly consumption for a given TS,

i – hour in yearly TS,

E_{Tot} – total energy consumption for specific country and scenario [TWh]

This way every country has total number of 15 time series for 2050 (5 scenarios multiplied by 3 historical time series).

DSM

The flexibility part of creating demand time series for 2050 is modelled in accordance to the Load Vision tool, and only covers **peak shaving**. This is the first step after normalization, as the potential for peak shaving was determined **only for current electricity uses**. Ability to shift new sources of load (EV and heating) is integral part of the calculation of the load profiles for those new uses.

The procedure for including DSM in demand time series is as follows. The first step is to determine the seasonal peak load in winter period (November, December, January & February); intermediate period (March, April, May, October) and summer period (June, July, August, September). The seasonal peak load value is reduced by the peak shaving potential value. This value is given directly by POYRY in their recommendations. The shaved energy will is moved to low load hours. The maximum peak shaving in a particular hour will be added to the hour with the lowest load; the second reduction due to peak shaving will be added to the hour with the second lowest load etc. The shaved energy will be moved within a range of ± 12 hours (an example should be given).

Electric vehicles

Given the uncertainty around charging patterns with widespread deployment of electric vehicles it is assumed that some of the electricity demand generated by cars will be of uncontrolled nature, i.e. based on driving patterns (group described as **non-responsive EV**), controlled nature, i.e. taking into account electricity price patterns. This group can be further divided into **semi active EV** and **fully active EV**. It was assumed that Semi active EV follow predefined weekly load charging pattern, whereas fully active EV have possibility to be charged according to the system needs/price signals.

The provided total energy load value [TWh] of electric vehicle demand directly for 2050 level. Basing on, internal within WP 2, discussion the split between particular groups of EV demand for considered scenarios was as presented in table 43:

	x-5	**x-7**	**x-10**	**x-13**	**x-16**
share of non-responsive EV	60%	40%	50%	60%	40%
share of semi active EV	30%	30%	40%	30%	30%
share of fully active EV	10%	30%	10%	10%	30%

Table 43: Share of particular types of EV charging patterns in scenarios

Uncontrolled electric vehicle demand profile

The baseline (uncontrolled) energy demand profile for electric vehicles should be based on driving patterns. This means that within day, vehicle use climbs sharply in the morning, and remains high (with some fluctuation) throughout the day until the evening peak, after which there is a sharp decline in driving. Electricity demand profile will peak in the early evening, with the level of charging then declining overnight. This is consistent with the assumption of home-based charging, whereby a vehicle would be plugged in and charged when it reaches home, with users requiring their vehicles to be (fully) charged in time for the morning driving peak. The daily load pattern is shown in figure 40.

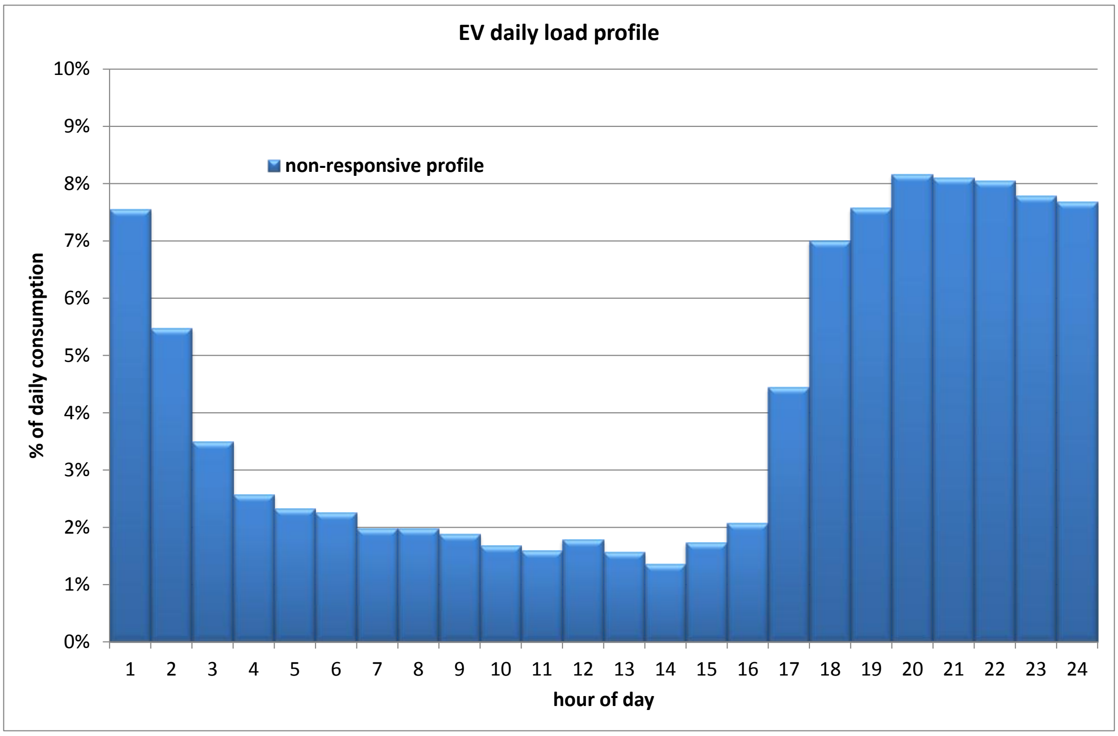

Figure 40: Uncontrolled electric vehicle daily load pattern

The consortium recommends that within a week vehicles are, on average, typically used less than at the weekends. It is uncertain though how this will translate into charging requirements. For example, a car may not be charged every day, and there may actually be more charging on a Sunday evening if users charge on a weekly basis. The recommendation in this matter is to not differentiate between working days and weekends in the uncontrolled charging profile. Moreover, they recommend using a flat electricity demand profile for electric vehicles across all months of the year.

Having all the data described above, the methodology to create uncontrolled electric vehicle demand profile is like this. Following table 42, take appropriate portion of total energy consumed by EV in given scenario for given country, then divide it by the number of days in a year. Then apply recommended daily profile (figure 41) for each day.

Controlled electric vehicle demand profile

According to this recommendation, controlled electric vehicle demand profile is considered in the two different timeframes: **within-day** and **within-week**. As recommended, given the size of the storage that would be required, shifting charging demand between months is not considered. The controlled within-day load profile for electric vehicles will follow an expected pattern of energy prices and is called the delayed charging profile. The initial profile was further modified within WP2, and the final profile used in the tool is shown in figure 42. As mentioned before this profile was used for both semi active and fully active EV. In further work associated with DSM, fully active part of EV was treated as available for optimisation.

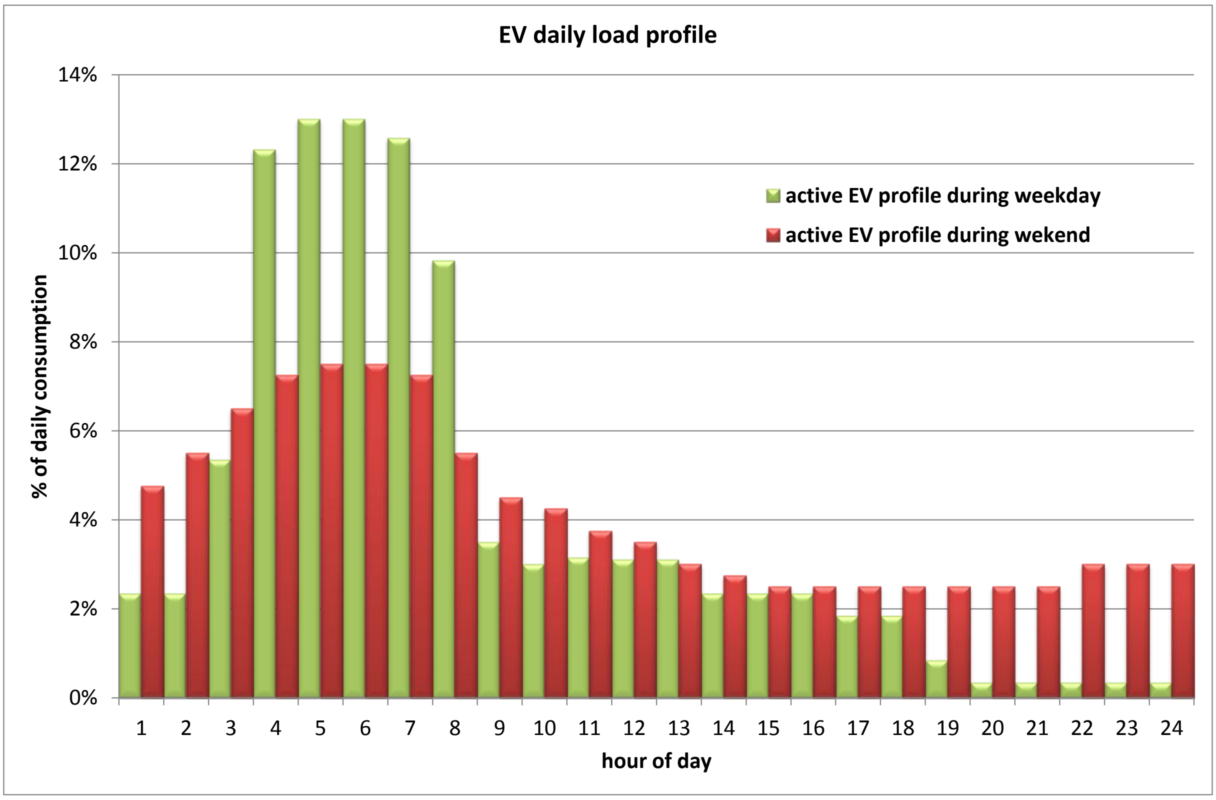

Figure 41: Controlled electric vehicle daily load pattern

The within week demand profile assumes that part of the demand on each weekday can be shifted into the weekend – this results in the following split of weekly demand on a daily basis:

Day of week	% of total week demand
Monday	10,70
Tuesday	10,70
Wednesday	10,70
Thursday	10,70
Friday	10,70
Saturday	23,25
Sunday	23,25
total	**100,00**

Table 44: Charging of EV during the week – share per day

Having all the data described above the methodology to create controlled electric vehicle demand profile is as follows. Following table 44, take appropriate portion of total energy consumed by EV in given scenario for given country and divide this by number of weeks. For given day check if it is weekday or weekend and multiply weekly demand either by 10.7% (for weekdays) or by 23.25% (for weekends). This will give daily energy consumption. Then apply recommended daily profile figure 41 for each day. In figure 42 comparisons of used daily profiles between weekends and weekdays for controlled and uncontrolled electric vehicles is shown.

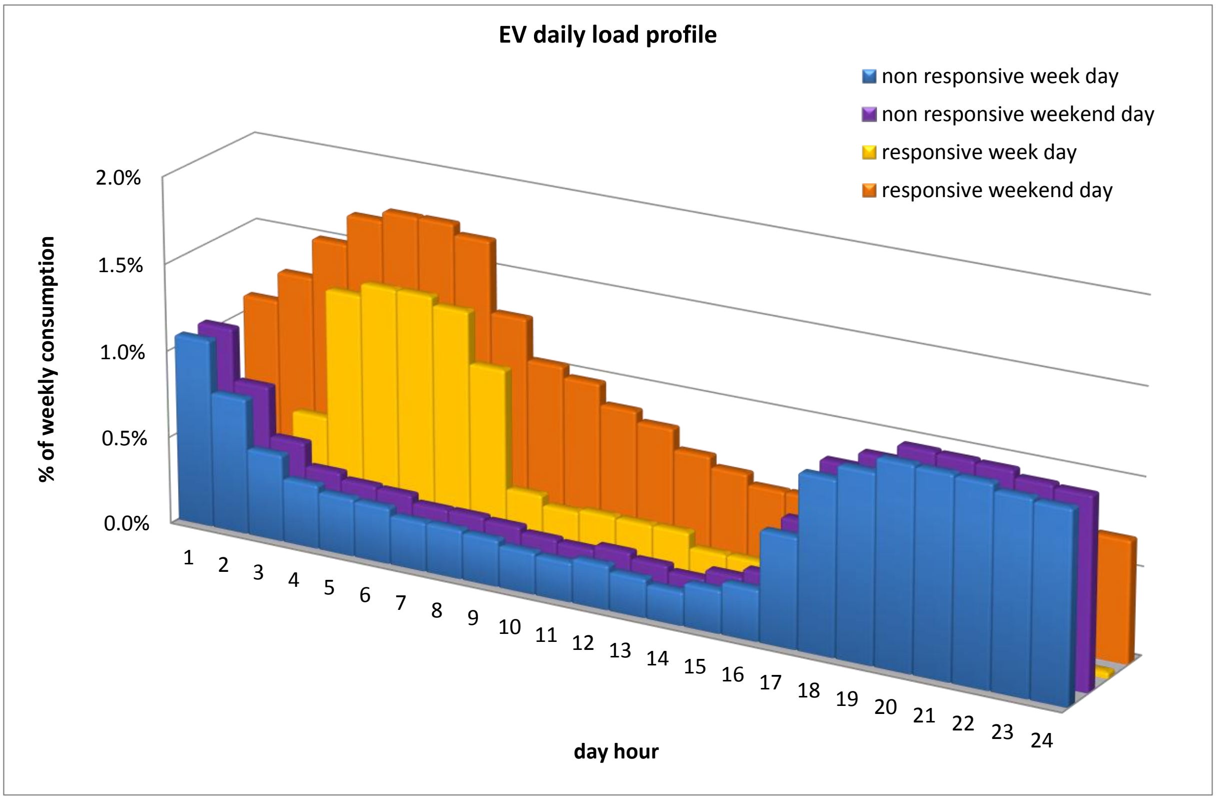

Figure 42: Comparison of used daily profiles between weekends and weekdays for controlled and uncontrolled electric vehicles

Heading

The baseline electricity demand profile for heating is obviously driven by the underlying demand for heat (which is obviously very sensitive to weather conditions). However, historical data on heating demand profiles is not systematically or widely available at country or regional level. Given the uncertainty around heating patterns with widespread deployment of electric space heating it is assumed that part of the electricity demand driven by heating will be residential, whereas the other part will be non-residential.

Within each group – residential and non-residential heating, additional type of request for heat can be distinguished: water heating and heating for technological processes.

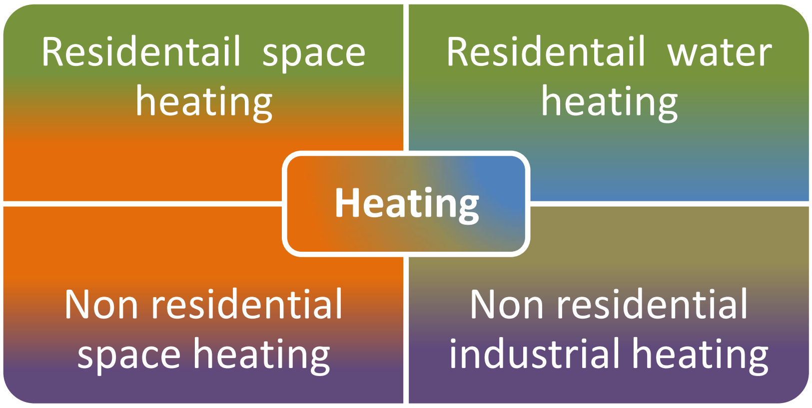

Figure 43: Components of heating contribution

Space heating

As the energy consumption is highly weather-dependent it was assumed that space heating energy consumption for each country will be a function of the average monthly temperature. So for each country average monthly temperature was derived from the website of The Royal Meteorological Institute of Belgium (RMI)[54]. This is the same source as used in "*GUIDELINES FOR CONSTRUCTING VISIONS 1 & 3*". The temperature data derived is presented in. When more than one city was available for the country, the capital was chosen. There was no data for Montenegro, so temperatures from Serbia (Belgrade) were taken as an input for calculations.

Moreover, it was assumed that **heating period** is for months with average temperature **lower than 10°C**, except for Portugal and Greece where temperature threshold was set to 13°C. The heating months are marked with orange colour in table 45.

Additional total energy consumption data, related to the demand driven by heating in 2050 provided, were divided into 4 groups:

- Additional load from heat pumps – residential.
- Additional load from heating other than heat pumps – residential.

[54] http://www.meteo.be/meteo/view/fr/6042865-Climats+dans+le+monde.html

- Additional load from heat pumps - non-residential.
- Additional load from heating other than heat pumps - non-residential.

It was found that although Air-to-Air and other than Air-to-Air heat pumps differ in energy consumption expressed in energy units, however hourly daily load profile expressed as percentage of total daily consumption is the same for both types. So it was assumed that data should be combined only into two groups: residential and non-residential heating.

For residential heating (following *GUIDELINES FOR CONSTRUCTING VISIONS 1 & 3. ANNEX 10* approach) it was assumed that consumption changes during a day according to hourly load pattern. Available hourly data was for +5.4°C and -5.5°C only, so simplified linear temperature dependency was assumed for each hour. Due to this, shape of daily load profile for residential heating is different for different temperatures (examples of daily load profiles for different temperatures are presented in figure 44.

For non–residential space heating, a flat across a day profile was assumed, based on total daily consumption calculated as a sum of hourly pattern described above. The algorithm for heating demand calculations is as presented in the figure 45.

Country	City	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Austria	Vienne	**-0.7**	**1.3**	**5.4**	10.2	14.7	17.8	19.7	19.2	15.5	10.2	**4.7**	**1.0**
Bosnia and Herzegovina	Sarajevo	**-0.9**	**1.5**	**5.1**	**9.4**	14.1	17.0	18.9	18.5	15.1	10.4	**5.3**	**0.3**
Belgium	Uccle	**2.5**	**3.2**	**5.7**	**8.7**	12.7	15.5	17.2	17.0	14.4	10.4	**6.0**	**3.4**
Bulgaria	Sofia	**-1.5**	**0.7**	**4.8**	10.4	14.6	18.0	19.8	20.7	16.1	10.7	**5.1**	**0.6**
Switzerland	Zurich	**-0.6**	**0.7**	**4.1**	**8.0**	12.2	15.5	17.6	16.7	13.9	**9.1**	**4.0**	**0.6**
Czech Republic	Prague	**-2.0**	**-0.6**	**3.1**	**7.6**	12.5	15.6	17.1	16.6	13.2	**8.3**	**3.0**	**-0.2**
Germany	Berlin	**-0.4**	**0.6**	**4.0**	**8.4**	13.5	16.7	17.9	17.2	13.5	**9.3**	**4.6**	**1.2**
Denmark	Copenhagen	**0.1**	**-0.1**	**2.0**	**5.6**	10.9	15.0	16.4	16.3	13.3	**9.6**	**5.1**	**1.8**
Estonia	Tallinn	**-5.5**	**-5.7**	**-2.2**	**3.4**	**9.7**	14.5	16.3	15.3	10.8	**6.3**	**1.2**	**-2.9**
Spain	Madrid	**5.5**	**7.0**	**9.3**	11.6	15.5	20.4	24.3	23.8	20.3	14.5	**8.9**	**5.9**
Finland	Helsinki	**-6.9**	**-6.8**	**-2.9**	**2.9**	**9.9**	14.9	16.6	15.0	10.0	**5.4**	**0.1**	**-4.1**
France	Paris	**3.5**	**4.5**	**6.8**	**9.7**	13.3	16.4	18.4	18.2	15.7	11.8	**6.9**	**4.3**
Great Britain	London	**3.5**	**3.8**	**5.7**	**8.0**	11.3	14.4	16.5	16.1	13.8	10.7	**6.4**	**4.5**
Greece	Athens	**10.2**	**10.5**	**12.4**	16.0	20.6	25.0	27.8	27.6	24.3	19.3	15.4	**12.0**
Croatia	Split	**7.4**	**8.1**	10.4	13.9	18.4	22.4	25.4	25.2	21.4	16.9	12.2	**8.7**

Country	City	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Hungary	Budapest	**-1.6**	**1.1**	**5.6**	11.1	15.9	19.0	20.8	20.2	16.4	11.0	**4.8**	**0.4**
Ireland	Dublin	**5.1**	**5.0**	**6.2**	**7.8**	10.4	13.3	15.0	14.7	13.0	10.6	**7.1**	**6.0**
Italy	Rome	**3.7**	**4.4**	**5.8**	**8.3**	11.9	15.6	18.2	18.4	15.8	12.0	**8.1**	**5.1**
Lithuania	Vilnius	**-6.1**	**-4.8**	**-0.6**	**5.7**	12.5	15.8	16.9	16.3	11.6	**6.6**	**1.2**	**-2.9**
Luxembourg	Luxembourg	**0.0**	**1.1**	**4.0**	**7.5**	11.8	14.9	16.9	16.4	13.4	**9.1**	**3.8**	**1.0**
Latvia	Riga	**-4.7**	**-4.2**	**-0.5**	**5.1**	11.4	15.5	16.9	16.2	12.0	**7.4**	**2.1**	**-2.3**
Montenegro	Belgrade	**0.4**	**2.7**	**7.1**	12.4	17.2	20.0	21.7	21.3	17.7	12.4	**7.0**	**2.3**
FYROM	Skopje	**0.2**	**3.2**	**7.6**	12.1	17.0	20.8	23.1	22.6	18.5	12.3	**5.7**	**1.2**
Netherlands	Utrecht	**2.2**	**2.5**	**5.0**	**8.0**	12.3	15.2	16.8	16.7	14.0	10.5	**5.9**	**3.2**
Norway	Oslo	**-7.2**	**-7.1**	**-2.3**	**2.8**	**9.4**	14.1	15.2	13.9	**9.3**	**4.7**	**-1.5**	**-5.7**
Poland	Warsaw	**-3.3**	**-2.1**	**1.9**	**7.7**	13.5	16.7	18.0	17.3	13.1	**8.2**	**3.2**	**-0.9**
Portugal	Lisbon	**11.4**	**12.3**	13.7	15.1	17.4	20.2	22.4	22.8	21.7	18.5	14.5	**11.8**
Romania	Bucharest	**-2.4**	**-0.1**	**4.8**	11.3	16.7	20.2	22.0	21.2	16.9	10.8	**5.2**	**0.2**
Serbia	Belgrade	**0.4**	**2.7**	**7.1**	12.4	17.2	20.0	21.7	21.3	17.7	12.4	**7.0**	**2.3**
Sweden	Stockholm	**-2.8**	**-3.0**	**0.1**	**4.6**	10.7	15.6	17.2	16.2	11.9	**7.5**	**2.6**	**-1.0**
Slovenia	Ljubljana	**-1.1**	**1.4**	**5.4**	**9.9**	14.6	17.8	19.9	19.1	15.5	10.4	**4.6**	**0.0**
Slovakia	Poprad	**-5.0**	**-3.2**	**0.7**	**6.0**	11.0	14.1	15.5	14.8	11.5	**6.7**	**1.3**	**-3.3**

Table 45: Average monthly temperature for analysed countries and months considered as heating period (marked with orange colour).

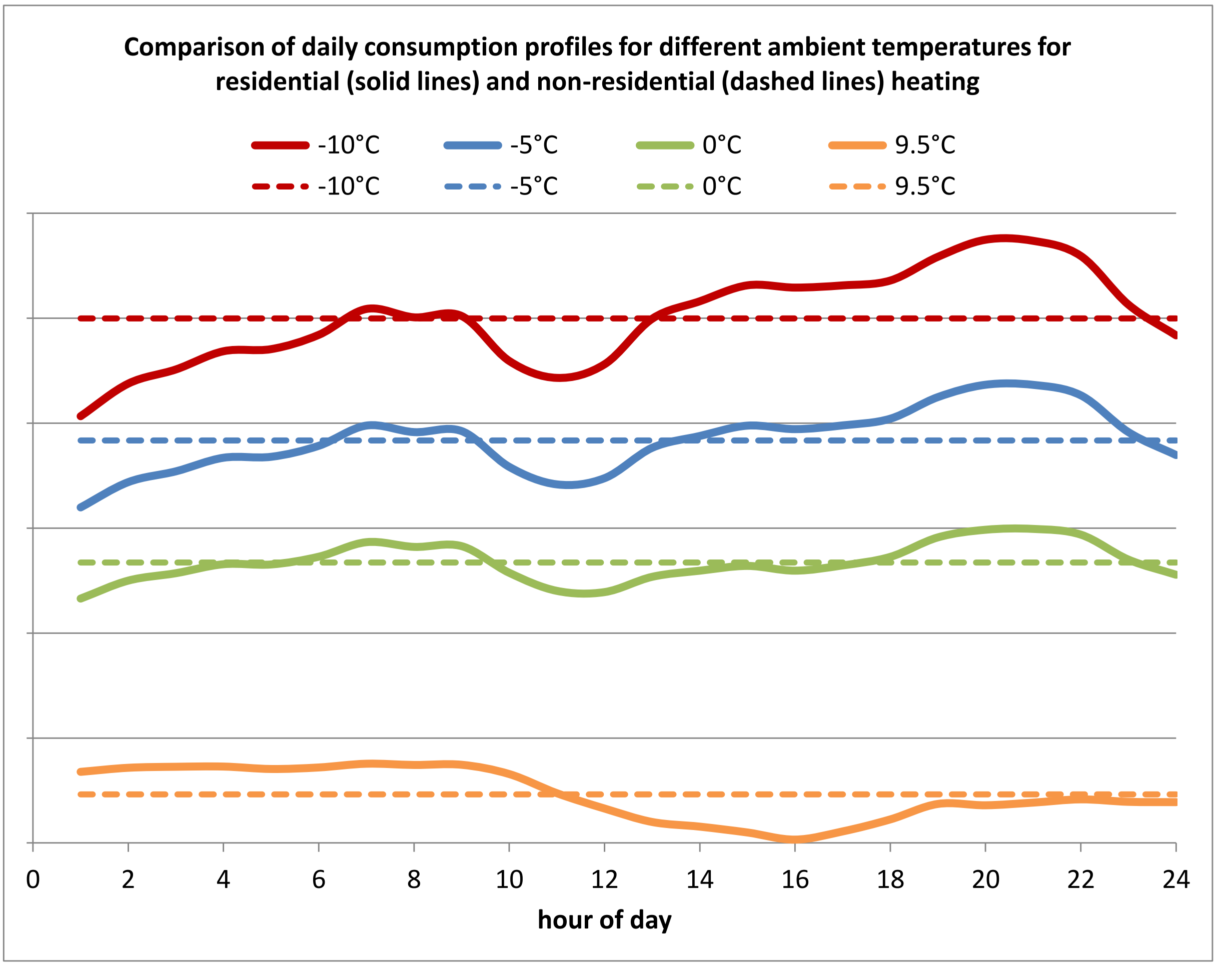

Figure 44: Examples of daily load profiles for different temperatures for residential heating.

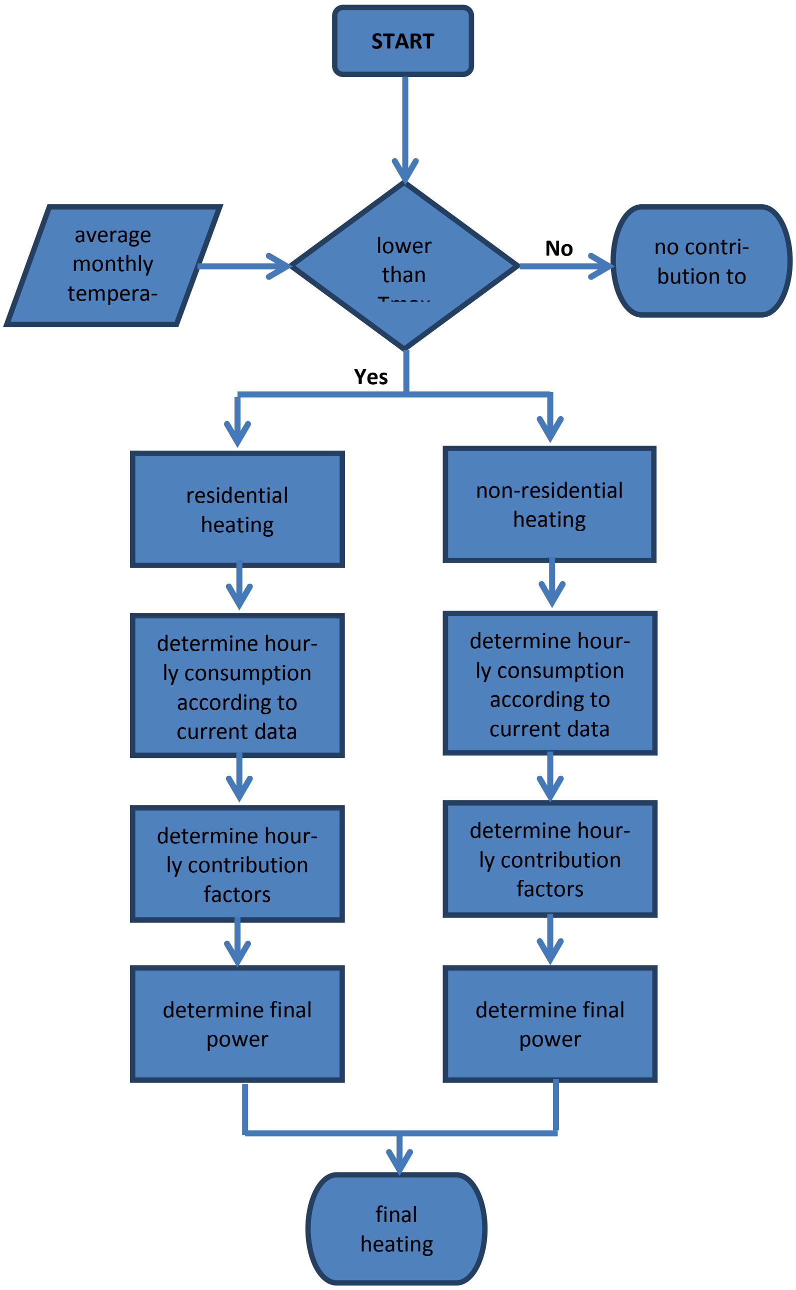

Figure 45: Algorithm for heating demand calculations

Hourly consumption according to current data is calculated as follows:

For residential heating:

$$P_{def\ \_i} = f(h, Temp)$$

For non-residential heating:

$$P_{\mathrm{def}_i} \quad = f(Temp)$$

Where:

P_{def_i} – power calculated according to current (default) data, [GW]

Temp – average monthly temperature,

h – hour of day,

i – hour in yearly TS.

Contribution factors are calculated as follows:

$$C_i = \frac{P_{def\ \_i}}{\sum_{i=m}^{n} P_{def\ \_i}}$$

Where:

C_i – contribution factor of each hour of the heating period,

m, n – first and last hour of heating period.

Final demand is calculated separately for residential and non–residential heating:

$$P_i = C_i * E_{Tot} * 1000\ E_{Tot}$$

Where:

E_{Tot} – total energy consumption for specific country and scenario [TWh] (separately for residential and non–residential heating).

Water heating

It was assumed that part of residential heating will be used for water heating. Share of this load is scenario dependent. Assumed values for particular scenarios are presented in table 46.

After internal within WP2 discussion, the load profile for water heating was presumed to be as presented in figure 40.

	x-5	x-7	x-10	x-13	x-16

share of water heating	40%	40%	30%	30%	30%

Table 46: Share of water heating as a part of residential heating in considered scenarios.

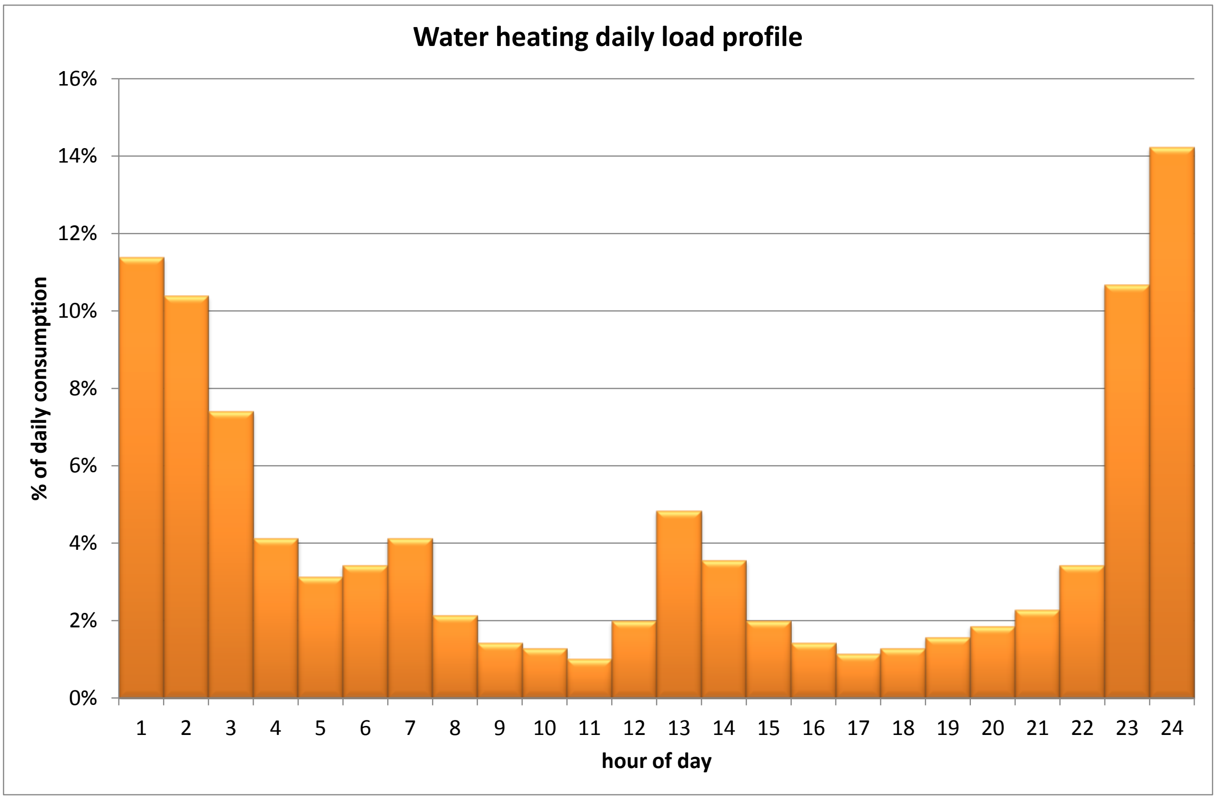

Figure 46: Water heating daily load profile

Heating for industrial processes

It was assumed that part of non-residential heating will be used for technological processes. After internal within WP2 discussion, it was decided that:

- share of this load is 50% in each scenario and
- flat across a year linear consumption

is applied.

Annex E: Calculation of demand side management

The algorithm

In this section, the proposed algorithm is discussed in general terms. The description assumes one technology suitable for DSM, but is easily expanded for multiple DSM-technologies, each with its own constraints. Here DSM should be understood as the possibility to control the demand in real time conditions.

Inputs

The algorithm requires the following time series as an input:

1) The original demand, per country, on an hourly basis, for the full year. These time series should contain the demand of new electricity use (e.g. heat pumps or EVs), without any DSM measures (historical and new electricity use).
2) The time series of the initial demand that stems from the new electricity use that is *candidate* for DSM measures. The initial demand is the demand of these technologies without the presence of any DSM measures. For example, for electric vehicles this would be the charging pattern of the electric vehicles if this charging pattern was uncontrollable.
3) The capacity of new electricity use appliances connected to the grid at every hour of the year. E.g. not all electric vehicles may be connected to a charging station at each hour of the day.
4) The time series that represents the net injection from non-dispatchable renewable resources (e.g. wind, solar).

All these inputs should be entered in the excel-file 'DSM.xlsx' under the tab 'Input' and put in the same folder as the executable 'DSM.exe' (see below). A specific macro excel sheet has been built to read/write directly the input/output in ANTARES. Description of the use of the excel sheet will be put in an Annex to this document.

Algorithm

In the algorithm, the residual demand, calculated as the original demand time series minus the injection of non-dispatchable renewables, is flattened to obtain a demand profile that mimics the demand profile under DSM measures. To obtain this profile, the following optimization problem is solved. Assuming one technology suited for DSM, this optimization problem can be summarized as follows:

$$\min\left[\frac{\sum_{t=1}^{T}\left(RD_t\ +DSM_t\right)^2}{T}-\left(\frac{\sum_{t=1}^{T}(RD_t-DSM_t)}{T}\right)^2\right]$$

$$\text{s.t.}\quad \forall t \qquad \sum_{t}^{t+T} DSM_t = 0$$

$$\forall t \qquad DSM_t \leq CAP_t^{DSM}$$

$$\forall t \qquad DSM_t \geq\ -POT_t^{DSM}$$

The objective function states that the DSM profile DSM_t (i.e. the change in the demand profile) is determined as such that the variability of the demand is minimized[55]. Demand shifting over a certain time period T can be done without an increase of the total demand ($\sum_t^{t+T} DSM_t = 0$), e.g. due to extra thermal losses in the buildings. Note that this also means that this does not take into account the possibility of load shedding or energy efficiency measures – i.e. the total demand does not decrease. The maximum increase of the demand profile at each time step is limited to the available capacity of the DSM technology CAP_t^{DSM}. The maximum decrease of the demand profile at each time step is limited to the current share of the DSM technology in the demand profilePOT_t^{DSM}.

Executing the algorithm:

1) Enter all inputs in the provided excel file.
2) Close the excel-file. *If the document is open, the algorithm won't work.*
3) Double click on the executable 'dsm.exe'. A new window pops up. It will close automatically when the algorithm is done.
4) Reopen the excel file. All output can be found under the tab 'Output'.

Output

The output contains the resulting DSM time series, as well as the optimized demand (i.e. the demand, taking into account DSM). The time series is plotted under the tab 'Figure – demand'. A load duration curve is shown under the tab 'Figure – LDC'.

Place within the ANTARES modelling framework

DSM should be applied on the residual demand. Therefore, this algorithm should be embedded in the envisioned modelling framework, as indicated below. First, based on the provided time series of demand and/or statistical properties of the RES, time series should be generated via the ANTARES time series generator. Each demand – RES Monte Carlo combination should then be passed on to the DSM tool, in order to optimize the residual demand. These optimized demand profiles could then be passed back to ANTARES,

[55] Other objective functions may be pursued, such as the minimization of the difference between the maximum and minimum demand on each day. The effect of different objective functions is discussed in Section 5.

where they are used as an input to the market model

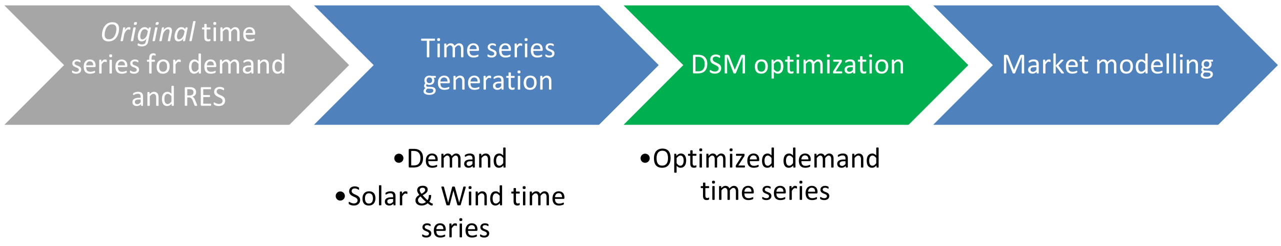

Figure 47: Place of the DSM tool within the modelling framework. Grey: input; Blue: Antares; Green: DSM tool.

Application in the *e-highway 2050* project[56]

Within the e-highway 2050 project, demand time series have been generated for each country by 2050 [see Annex D]. New use of electricity (i.e. electricity consumption of EVs and electric heating) has been included as described in [see Annex D]. In these time series, no demand side management measures are included. As a result of the high penetration of EVs and electric heating, peak demands are very high. E.g. the peak demand in Germany would be about 160 GW, twice the peak demand of today. However, this demand time series has been developed without taking into account any possibility of *active demand side management*.

The goal of the presented algorithm is to optimize the developed demand profiles, taking into account 'active' demand side management. Three 'sources' of flexibility are considered in the framework of this study:

- *electric heating*
- *electric vehicles*
- *electricity consumption of appliances*

For each of these technologies, assumptions on the flexibility that they hold need to be made, in order to estimate how much and on what time scale their consumption can be rescheduled. The former allows determining the RHS of the constraints CAP_t^{DSM} and POT_t^{DSM}, the latter provides information on T. These parameters should be adjusted in light of the spirit of the considered scenario. As flexibility was not discussed in the technology assessments [DSM-2, DSM-3], it was necessary to make some assumptions – which are of course open for discussion.

Electric heating

The methodology for determining the electricity demand profile from electric heating is described in [see Annex D]. In summary, a fixed hourly heating profile is proposed for each day. For residential heating, the demand for space heating profile is dependent on the hourly temperature. A flat profile is assumed for the demand for water heating. For non-residential heating, a flat profile is assumed for space heating. This profile is rescaled depending on the average temperature of the considered month. The heating demand is

[56] In this section, the methodology that has been employed to calculate the demand time series is merely summarised, because these time series will provide the needed input for the DSM tool. Understanding the underlying assumptions is needed to interpret the results of the DSM tool.

only considered if the average monthly temperature is lower than 10°C (13°C for countries in the south of Europe). Non-residential, technological process heating is assumed flat throughout the year.

However, this methodology does result in the same load profiles during the weekends and on weekdays. One might consider:

- Higher heating demand during weekends (more people are at home during the weekend), but with a different load profile;
- Lower non-residential heating demands during weekends;
- Lower heating demands during the weekdays.

Furthermore, it causes abrupt changes in electricity demand at the end and beginning of the heating season.

The following assumptions on the constraints in the DSM optimization have been considered:

- $POT_t^{DSM} = B \cdot DEM_t^{HEATING,ORIGINAL}$: The portion of the demand from electric heating that is suited for DSM is set to a certain percentage B of the original heating demand. This percentage will depend on the scenario.
- $CAP_t^{DSM} = B \cdot [\max(DEM_t^{HEATING,ORIGINAL}) - DEM_t^{HEATING,ORIGINAL}]$: The maximum additional demand at each time step is limited to B percent of the difference between the installed capacity of heating systems ($\max(DEM_t^{HEATING,ORIGINAL})$) and the original heating demand.
- T = 4: Given the high standards in terms of insulation, a reasonably high time constant could be considered for the heating demand. Here 4 hours are proposed, but this might be adapted depending on the country and scenario considered.

<u>Electric vehicles</u>

Electric vehicles are split in responsive and unresponsive (or semi-active) electric vehicles [see Annex D]. Both categories are characterized by a fixed daily charging profile. For the unresponsive vehicles, the annual demand from these EVs is distributed equally the year. The annual demand from the responsive electric vehicles is distributed is likewise, but part of the daily demand is shifted to the weekends.

The current methodology results in some rather peculiar effects:

- due to the shift of a part of the demand of the EVs to the weekend, this results in *higher* demand of EVS during the weekends than during weekdays;
- EVs ‘respond’ in the same way, regardless of the season. For example, shifting demand from the EVs from the late afternoon to the night might be reasonable during winter. However, during summer time, with high solar power penetrations, you might better of shifting to mid-day, as electric power from PV may be abundantly available.

Therefore, a (limited) adaptation of the weekly division of demand to avoid equal (or even higher) load (patterns) during weekends would be suggested. With regard to the ‘response’ of the EVs, the DSM tool should be used.

The following assumptions on the constraints for the DSM optimization are proposed:

- $POT_t^{DSM} = C \cdot DEM_t^{EV,ORIGINAL}$: The portion of the demand from EVs that is suited for DSM is set to a certain percentage C of the original electric demand. This percentage will depend on the scenario.
- $CAP_t^{DSM} = C \cdot CF_t \cdot [\max(DEM_t^{EV,ORIGINAL}) - DEM_t^{EV,ORIGINAL}]$: The maximum additional demand at each time step is limited to C percent of the difference between the charging capacity of the EVs ($\max(DEM_t^{EV,ORIGINAL})$) and the original EV electricity demand. The correction factor CF_t represents the percentage of vehicles at each time step t that is available for charging: i.e. not on the road and connected to a charging station. The proposed CF is depicted in figure 45. Note that this is a mere proposal, not founded in any research, to get the discussion going.
- T = 8. Again, merely an assumption.

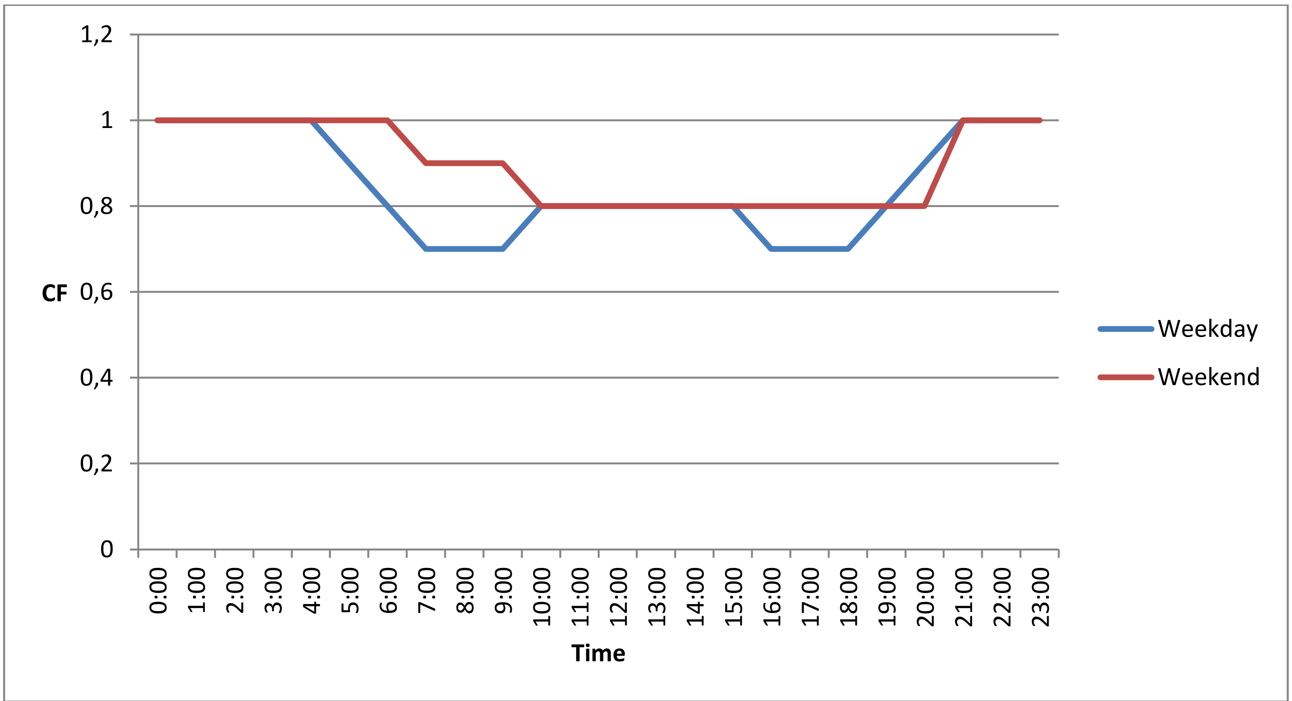

Figure 48: The proposed correction factor for the availability of the EVs.

<u>Electricity consumption of appliances</u>

In general, no information on the electricity consumption of appliances in 2050 is available. However, it seems reasonable that a certain portion of appliances will be subjected to demand side management. Here it is assumed that a certain percentage A of the original demand DEM_t^{org} – i.e. excluding new use – is available for DSM and that this demand can be rescheduled over the whole day:

- $CAP_t^{DSM} = POT_t^{DSM} = A \cdot DEM_t^{org}$

- $T = 24$

Summary

Table 47 summarises the proposed assumptions on the constraints on the flexibility of the various DSM technologies. Note that the constraints and values below are up for discussion. Especially WP3 should provide input here.

	Electric heating	Electric vehicles	Appliances
$\boldsymbol{CAP_t^{DSM}}$	$B \cdot [\max(DEM_t^H) - DEM_t^H]$	$C \cdot CF_t \cdot [\max(DEM_t^{EV}) - DEM_t^{EV,}]$	$A \cdot DEM_t^{org}$
$\boldsymbol{POT_t^{DSM}}$	$B \cdot DEM_t^H$	$C \cdot DEM_t^{EV}$	$A \cdot DEM_t^{org}$
$\boldsymbol{T}$	*4*	*8*	24

Table 47: Summary of the proposed assumptions on the constraints on the DSM optimisation

Results and discussion

Below the effect of different objective functions, as well as the flexibility of EVs, electric heating and appliances will be discussed. First, the effect of different objective functions, assuming only appliances are subject to DSM, will be elaborated. Second, the flexibility of the electric vehicles and electric heating will be added. For numerical results, the provided demand time series for Portugal in 2050 will be used. The user can modify all assumptions on the flexibility of the appliances, as well as the settings for the optimization via the excel-file 'DSM.xlsx'. All assumptions can be found under the tab 'Input'.

Effect of different objective functions

The situation in which 5% of the original demand can be shifted over the 24 hours will be examined. The optimization is performed on a daily basis. Three objective functions[57] are considered:

- Minimum variance of the residual demand, as presented in Section 1;
- Minimum peak demand (in each day);
- Minimum difference between the maximum and minimum demand (in each day).

The results are summarized in figures 49 to 56 and the table 48 below. As shown in the figures and in the table, there is no clear difference between the three approaches. However, simply minimizing the peak demand does not lead to a good redistribution (low minimum demand), nor does it leads to lower annual peak demand more than the other two approaches. The two other objective functions yield similar results. In what follows, we will use the 'minimum variance' objective function.

[57] The user can select the various objective functions via the excel interface (Tab 'Input').

[GW]	Orig. demand	Min. Variance	Min. Peak demand	Min. Delta demand
Min. demand	*5.07*	*5.650*	*5.084*	*5.650*
Max. demand	*22.61*	*22.110*	*22.110*	*22.110*
Avg. demand	*9.92*	*9.917*	*9.917*	*9.917*

Table 48: Effect of the different objective functions on the DSM optimisation

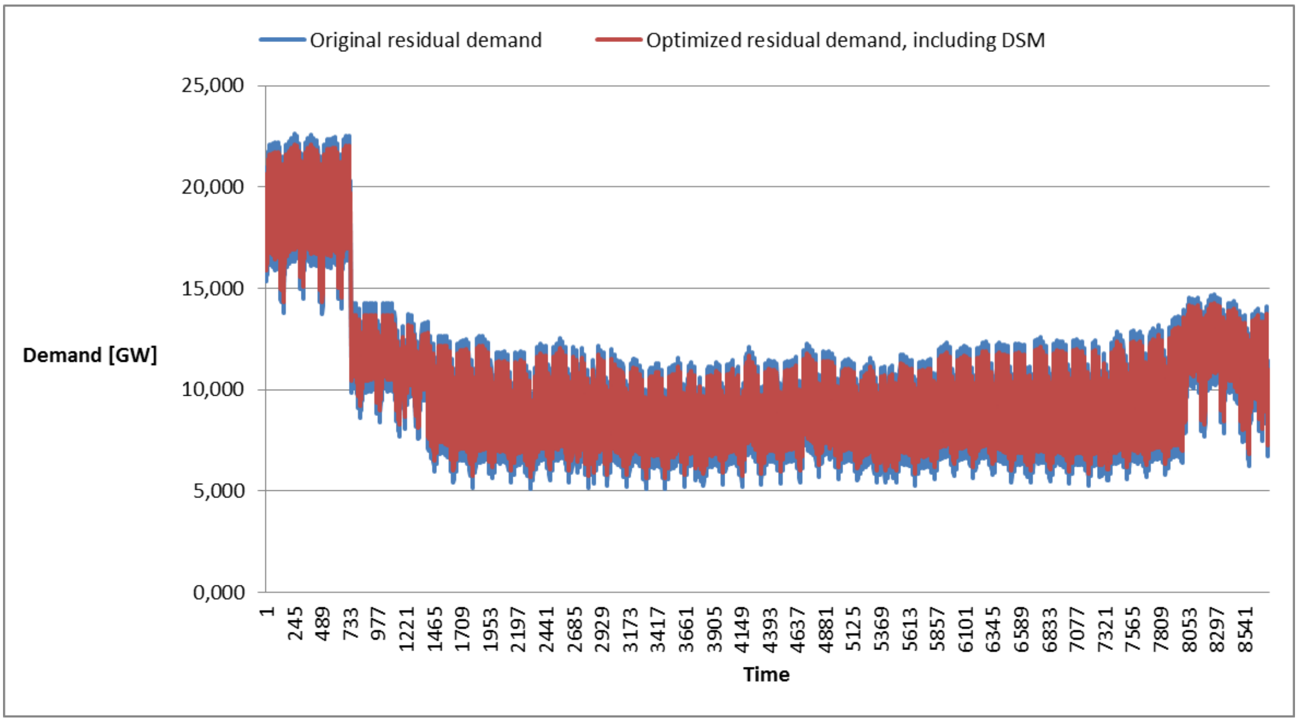

Figure 49: Min. variance – optimised demand

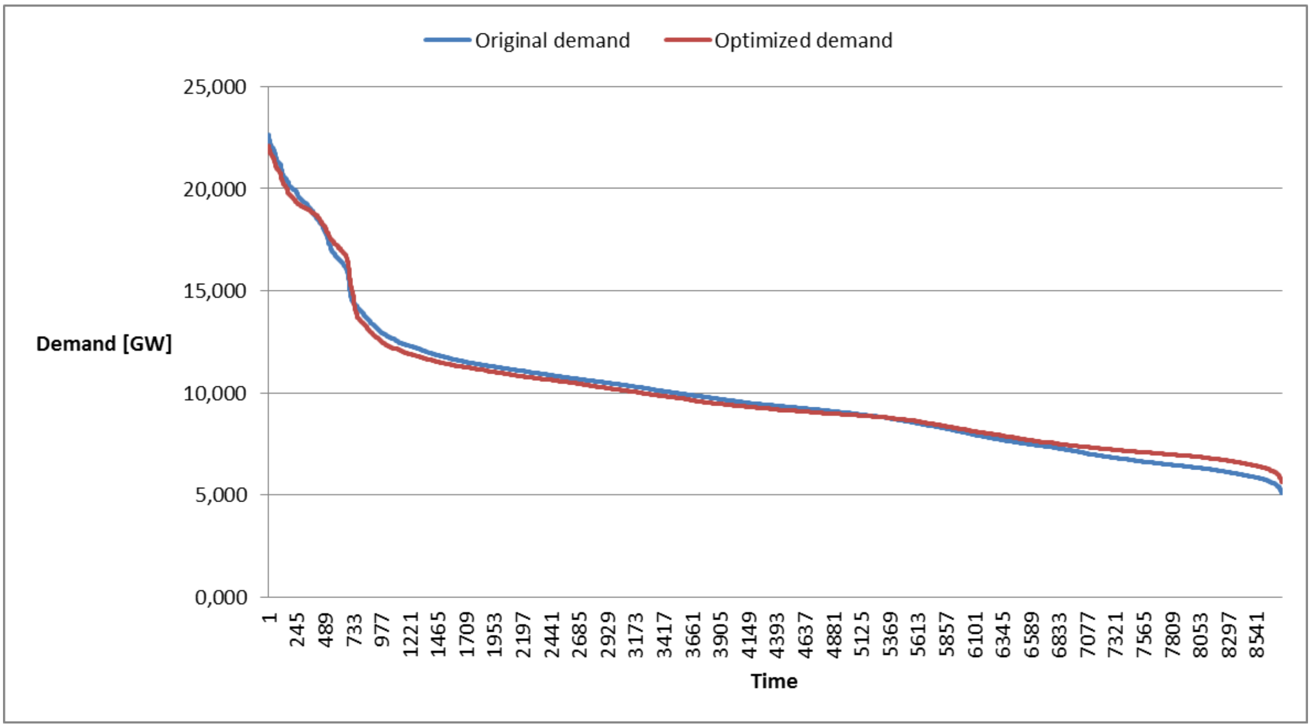

Figure 50: Min. variance - load duration curve

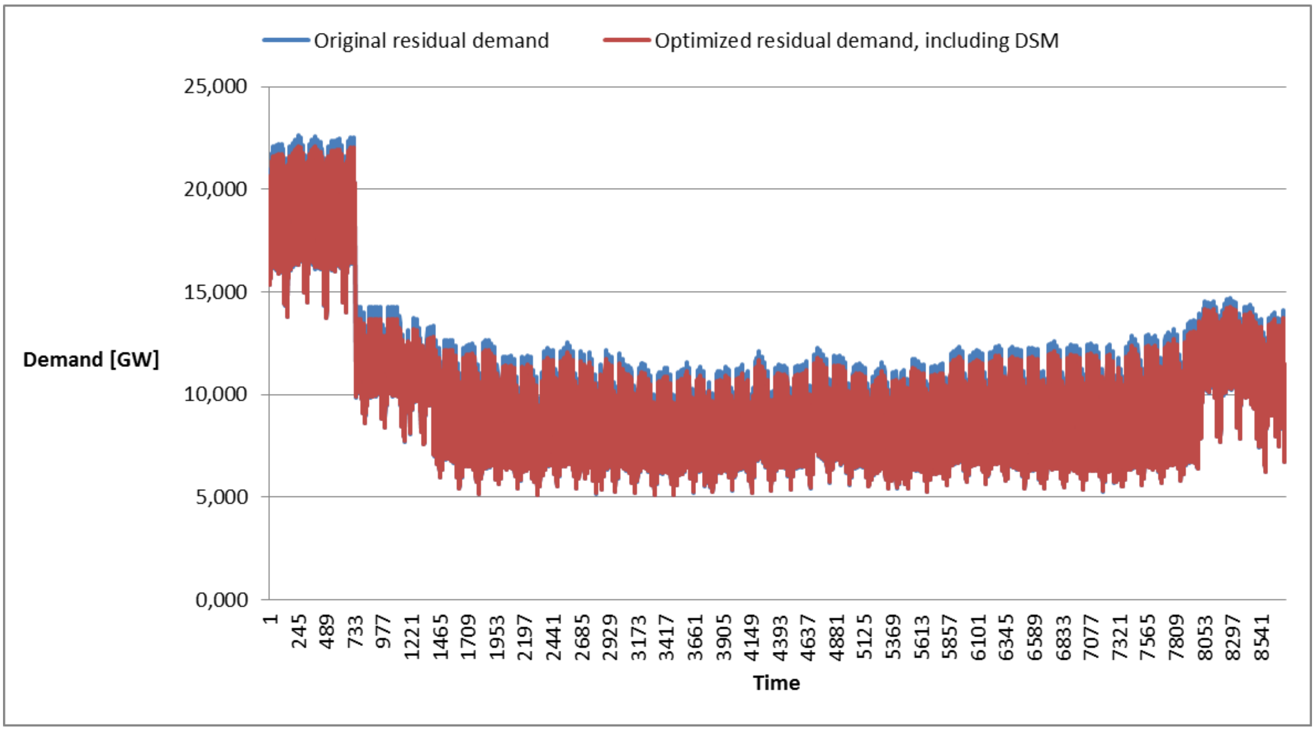

Figure 51: Min. peak demand - optimised demand

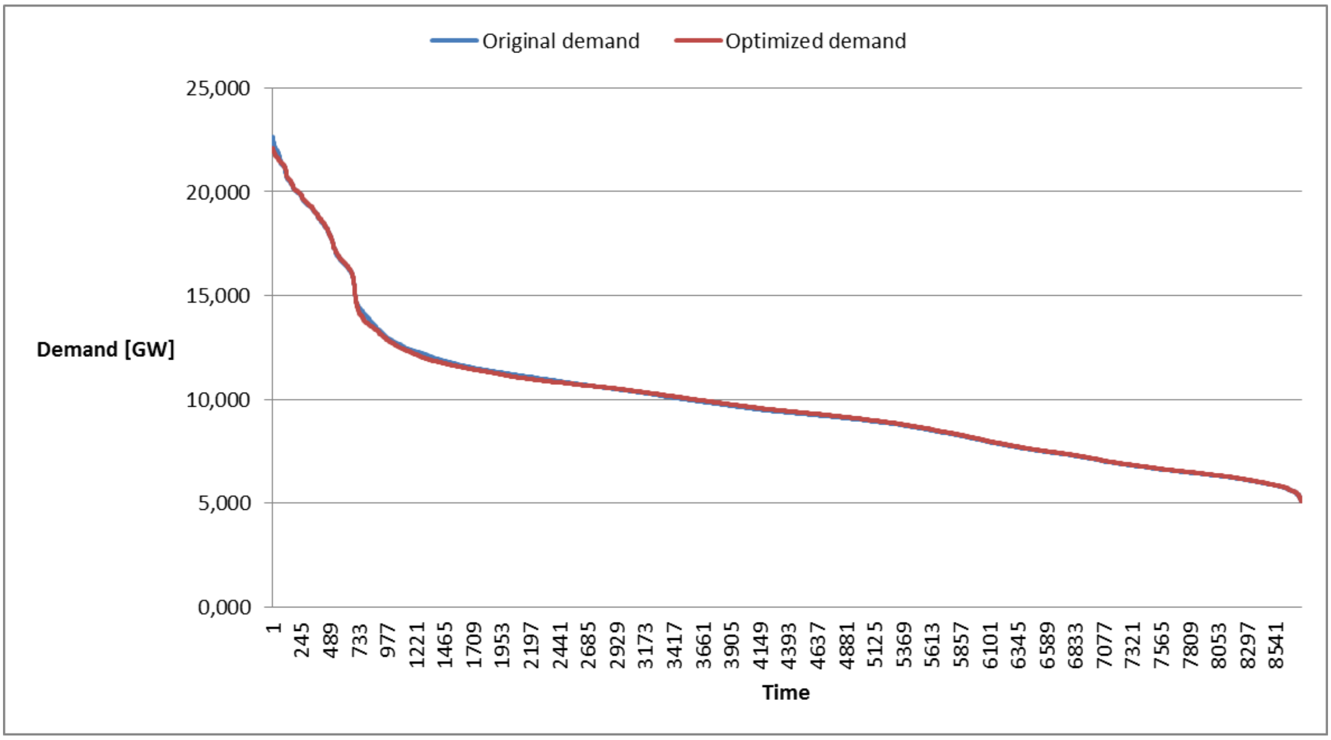

Figure 52: Min. peak demand - load duration curve

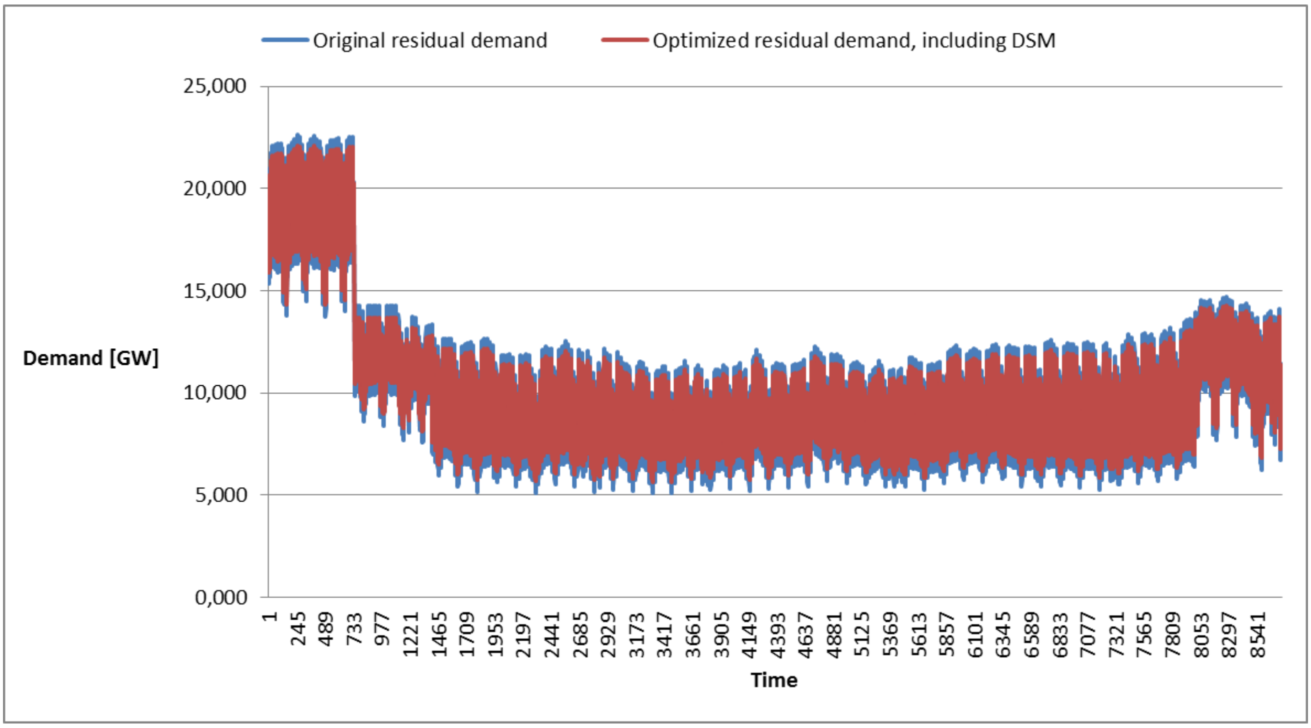

Figure 53: Min. difference between maximum and minimum demand - optimised demand

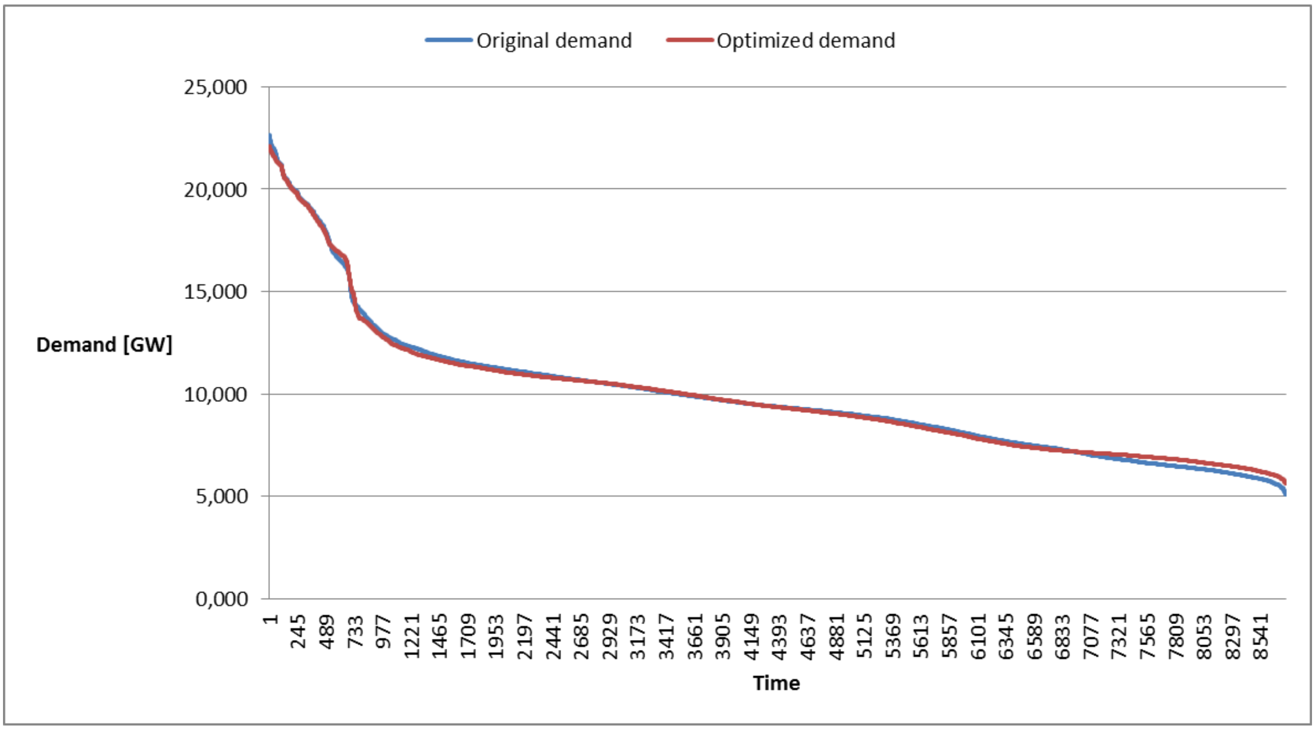

Figure 54: Min. difference between maximum and minimum demand - load duration curve

<u>Effect of the flexibility of EVs</u>

It is assumed that 25% of all EVs are responsive (in addition to the appliances). The CF is shown in figure 45. It is assumed that the demand can be redistributed within 8 hours. The peak demand decreases to 22.099 GW.

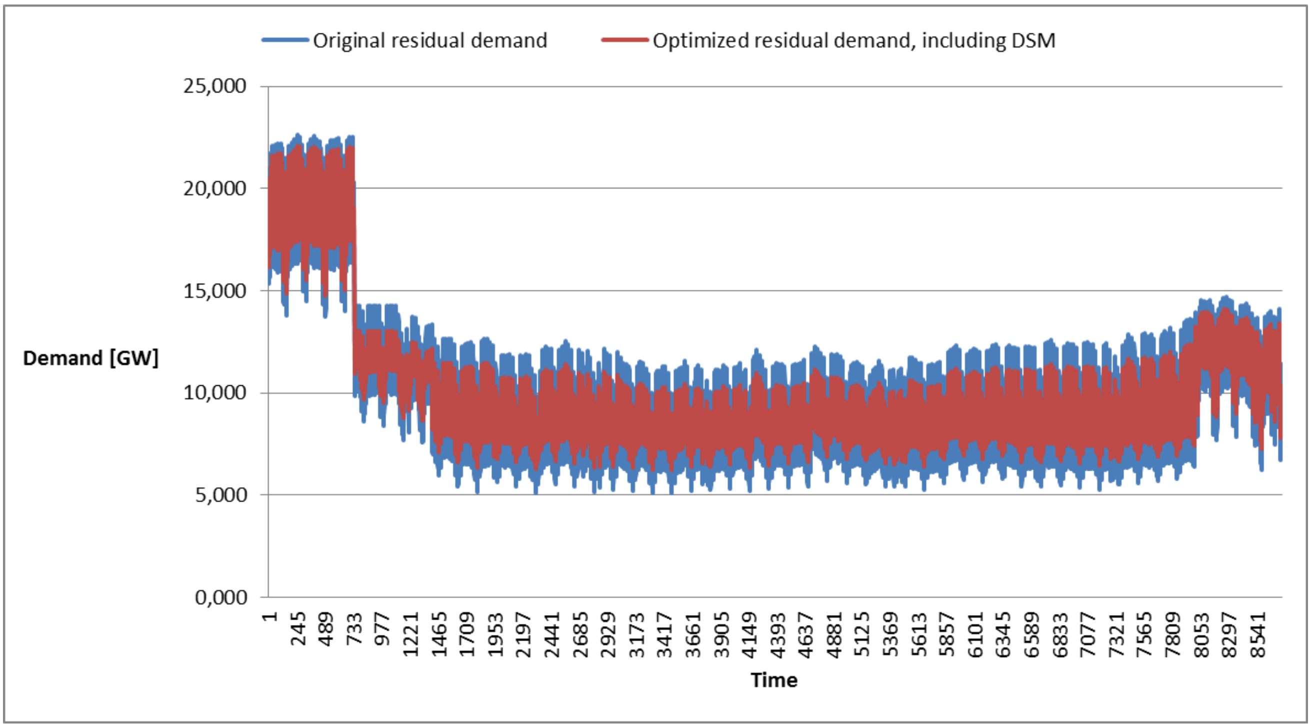

Figure 55: Effect of the EVs – optimised demand.

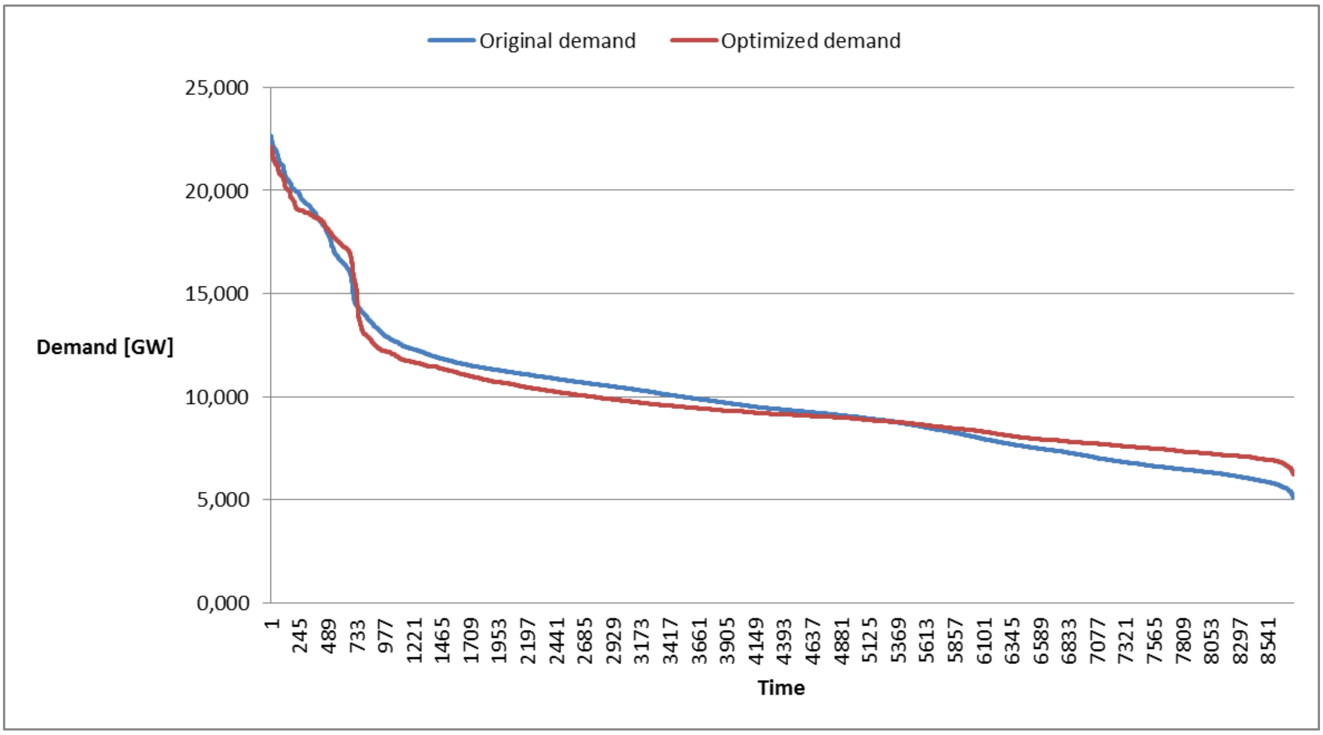

Figure 56: Effect of the EVs - optimised demand.

Effect of the flexibility of electric heating

We assume that 25% of the electric heating demand is flexible and can be redistributed over 4 hours. The result is shown in figure52-52. Peak demand further drops to 19.411 GW.

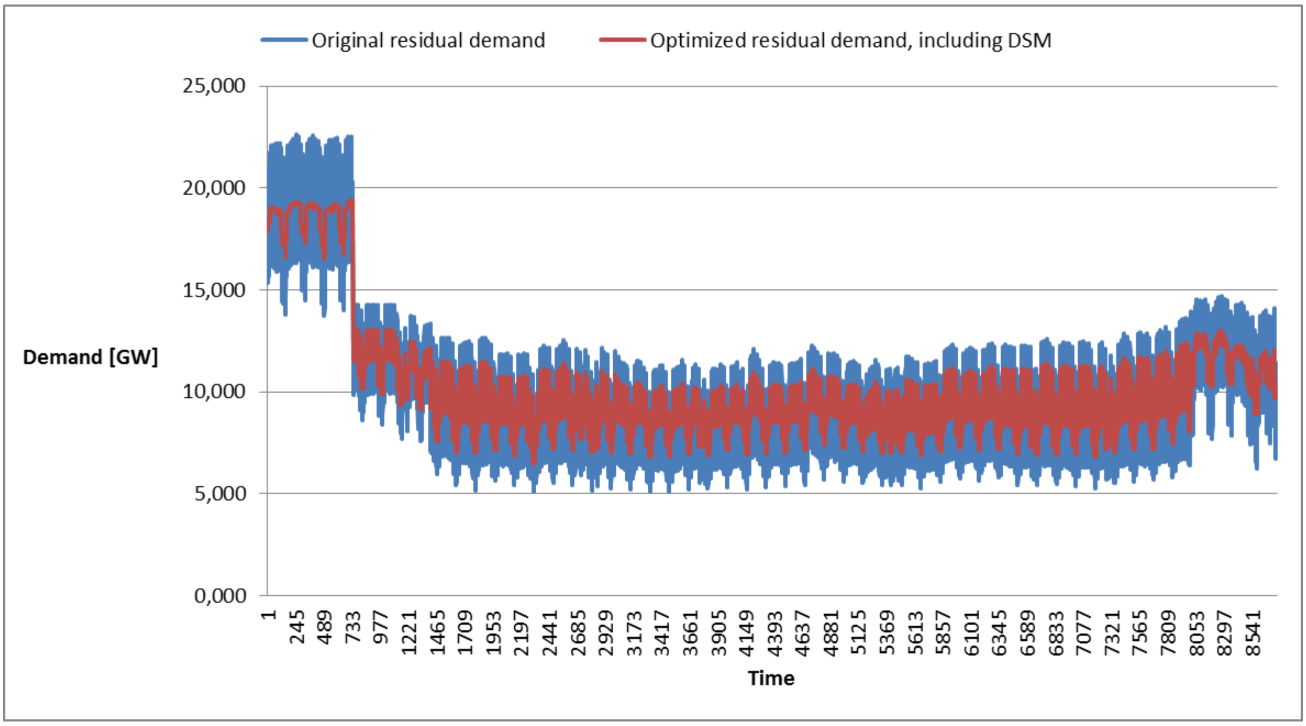

Figure 57: Effect of electric heating - optimised demand.

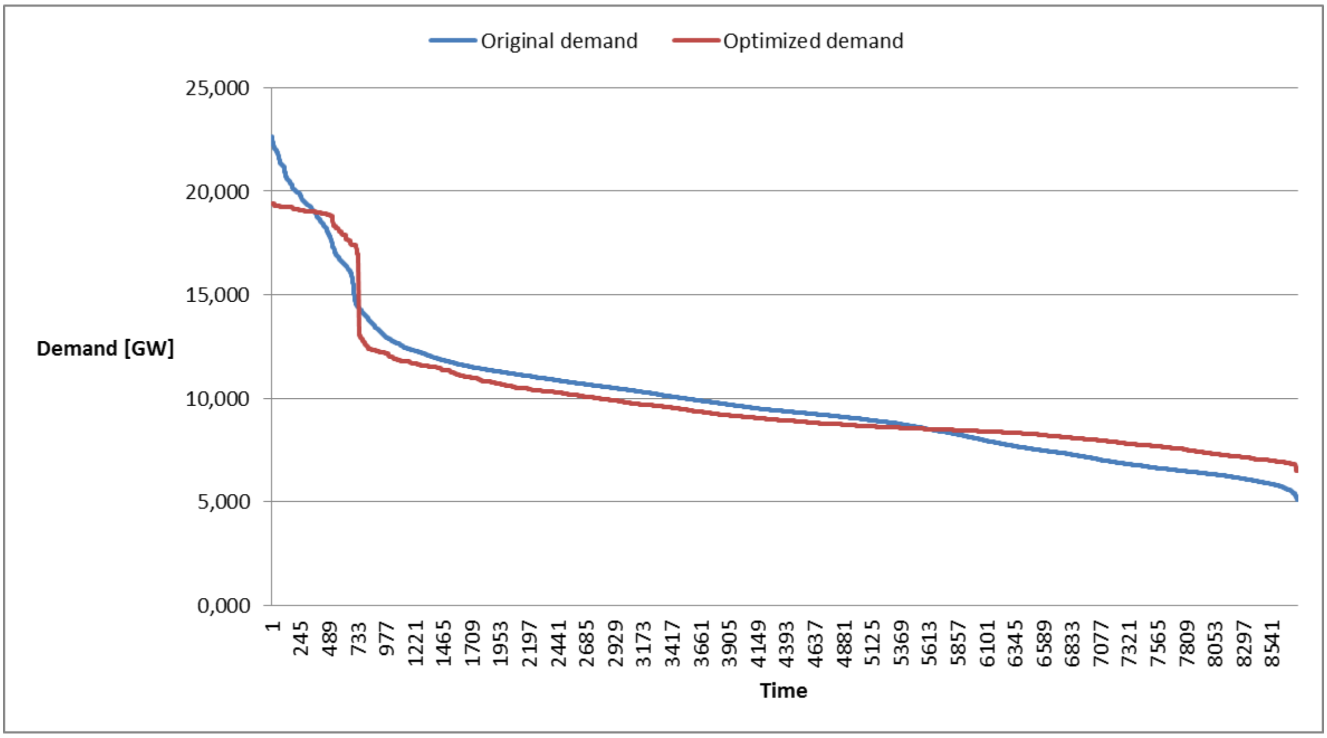

Figure 58: Effect of the electric heating - load duration curve.

Summary

In this document, a first draft of a methodology to assess the effect of DSM on demand time series for three technologies – electric heating, electric vehicles and general appliances – has been presented. In a very specific setting – namely Portugal, 2050 – we have shown that

- minimising the variance of the demand is an adequate objective function;
- demand side management can lower peak demand to by 3.2 GW, from 22.616 to 19.411 GW.

In this case, mainly flexibility from electric heating will result in a significant decrease in peak load. However, due to the relation between the proposed demand of the electric vehicles and the flexibility, peak demand might not decrease as much as one might suspect at first sight.

Used Input data And Assumptions:

- ***Electric vehicles:***
  The shares of passive, semi-active and active electric vehicle per scenario are given per scenario in the table 49 below:

	x-5	x-7	x-10	x-13	x-16
share of non-responsive EV	60%	40%	50%	60%	40%
share of semi-active EV	30%	30%	40%	30%	30%
Share of fully active EV	10%	30%	10%	10%	30%

Table 49: Shares of passive, semi-active and active electric vehicle per scenario

- ***Electric heating – residential space heating and domestic hot water production:***
  The shares of passive, semi-active and active electric heating per scenario are given per scenario in the table 50 below:

	x-5	x-7	x-10	x-13	x-16
Share of semi-active residential heating	20%	20%	15%	15%	15%
Share of fully-active residential heating	20%	26%	15%	15%	22%
Share of semi-active non-residential heating	0%	0%	0%	0%	0%
Share of fully-active non-residential heating	0%	5%	0%	0%	0%

Table 50: Shares of passive, semi-active and active electric heating per scenario

- ***White good appliances – e.g. washing machines.***
  It was further assumed that 25% of the technical potential for DSM, estimated from data provided by WP3, is tapped by 2050. This leads to the following compositions of demand in the countries per scenario.

Resulting shares of semi-active demand per country:

	X-5	X-7	X-10	X-13	X-16
Austria	6%	6%	4%	3%	3%
Belgium	6%	6%	4%	3%	3%
Bosnia and Herzego-vina	4%	4%	3%	2%	1%
Bulgaria	5%	5%	5%	4%	2%
Croatia	7%	7%	6%	5%	3%
Czech Republic	6%	6%	4%	3%	2%
Denmark	8%	8%	6%	5%	3%
Estonia	5%	5%	3%	3%	2%
Finland	4%	4%	3%	2%	1%
France	6%	6%	5%	4%	3%
FYROM	5%	5%	5%	4%	2%
Germany	6%	6%	5%	4%	3%
United Kingdom	10%	10%	8%	6%	5%
Greece	6%	6%	4%	3%	2%
Hungary	5%	5%	3%	3%	2%
Ireland	7%	7%	5%	4%	3%
Italy	6%	6%	5%	4%	3%
Latvia	4%	4%	3%	3%	2%
Lithuania	4%	4%	3%	3%	2%
Luxembourg	6%	6%	4%	3%	2%
Montenegro	6%	6%	6%	5%	2%
Netherlands	5%	5%	4%	3%	2%

	X-5	X-7	X-10	X-13	X-16
Norway	2%	2%	2%	2%	1%
Poland	9%	9%	7%	5%	3%
Portugal	4%	4%	3%	3%	2%
Romania	9%	9%	8%	6%	4%
Serbia	6%	6%	6%	5%	3%
Slovakia	5%	5%	4%	3%	2%
Slovenia	7%	7%	5%	4%	3%
Spain	4%	4%	5%	3%	2%
Sweden	5%	5%	4%	3%	2%
Switzerland	5%	5%	3%	3%	2%

Table 51: Shares of semi-active demand per country

Note: the difference between countries can be explained by the different volumes of heating and electric vehicles.

Resulting shares of fully active demand per country:

	X-5	X-7	X-10	X-13	X-16
Austria	4%	8%	2%	2%	4%
Belgium	5%	8%	2%	2%	4%
Bosnia and Herzego-vina	3%	5%	1%	1%	3%
Bulgaria	3%	6%	2%	2%	3%
Croatia	4%	9%	2%	2%	4%
Czech Republic	5%	8%	2%	2%	4%
Denmark	6%	11%	3%	3%	5%
Estonia	4%	6%	2%	2%	3%
Finland	3%	6%	1%	1%	3%
France	4%	7%	2%	2%	4%
FYROM	3%	6%	2%	2%	4%
Germany	4%	8%	2%	2%	4%

	X-5	X-7	X-10	X-13	X-16
United Kingdom	7%	12%	3%	3%	6%
Greece	4%	7%	2%	2%	4%
Hungary	4%	7%	2%	2%	3%
Ireland	5%	9%	2%	2%	4%
Italy	4%	7%	2%	2%	4%
Latvia	3%	5%	2%	2%	3%
Lithuania	3%	5%	1%	1%	3%
Luxembourg	4%	8%	2%	2%	4%
Montenegro	4%	7%	2%	2%	4%
Netherlands	4%	7%	2%	2%	4%
Norway	2%	3%	1%	1%	2%
Poland	6%	11%	3%	3%	5%
Portugal	2%	5%	2%	2%	3%
Romania	6%	11%	3%	3%	5%
Serbia	4%	7%	2%	2%	4%
Slovakia	4%	7%	2%	2%	4%
Slovenia	5%	9%	2%	2%	4%
Spain	3%	5%	2%	2%	3%
Sweden	3%	6%	2%	2%	3%
Switzerland	4%	7%	2%	2%	3%

Table 52: Shares of fully active demand per country

Annex F: Wind and solar potentials per country and cluster

Potentials per country:

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
AL	1	2	3	6	11	16	-
AT	8	-	8	13	30	43	-
BA	3	-	3	6	11	17	-
BE	12	0	13	19	3	22	-
BG	4	1	5	9	21	30	-
CH	2	-	2	14	19	32	-
CZ	12	-	12	15	8	23	-
DE	110	6	116	103	39	141	-
DK	24	1	24	9	7	16	-
EE	10	10	20	2	4	6	-
ES	71	11	82	76	137	214	50
FI	22	23	45	8	17	26	-
FR	180	20	200	106	99	205	7
GR	16	14	30	17	40	57	11
HR	4	4	7	7	11	18	-
HU	6	-	6	13	16	29	-
IE	34	11	45	9	11	20	-
IT	32	16	49	96	70	165	19
LT	28	1	29	4	6	10	-
LU	1	-	1	1	0	1	-
LV	20	6	26	3	4	7	-
ME	1	-	1	1	4	5	-

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
MK	0	-	0	3	9	12	-
NL	18	-	18	25	6	31	-
NO	32	28	60	9	144	153	-
PL	126	6	132	50	31	81	-
PT	10	4	14	15	19	34	11
RO	3	3	6	27	32	58	-
RS	2	-	2	11	13	24	-
SE	41	20	61	16	95	111	-
SI	1	-	1	3	2	5	-
SK	6	-	6	8	5	13	-
UK	127	25	152	111	147	258	-

Table 53: Potentials per country

Potentials per cluster:

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
70_AL	1	2	**3**	6	11	**16**	**0**
49_AT	1	0	**1**	3	20	**23**	**0**
50_AT	1	0	**1**	4	8	**12**	**0**
51_AT	6	0	**6**	6	2	**8**	**0**
63_BA	3	0	**3**	6	11	**17**	**0**
28_BE	12	0	**13**	19	3	**22**	**0**
66_BG	4	1	**5**	9	21	**30**	**0**
47_CH	1	0	**1**	12	7	**19**	**0**
48_CH	1	0	**1**	1	12	**13**	**0**

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
39_CZ	4	0	**4**	9	5	**13**	**0**
40_CZ	8	0	**8**	7	3	**10**	**0**
31_DE	32	0	**32**	19	8	**27**	**0**
32_DE	25	6	**31**	11	7	**18**	**0**
33_DE	14	0	**14**	25	3	**28**	**0**
34_DE	21	0	**21**	11	5	**16**	**0**
35_DE	10	0	**10**	16	4	**19**	**0**
36_DE	3	0	**3**	3	3	**6**	**0**
37_DE	5	0	**5**	18	8	**26**	**0**
38_DK	19	0	**19**	5	6	**11**	**0**
72_DK	5	1	**6**	4	1	**5**	**0**
73_EE	10	10	**20**	2	4	**6**	**0**
01_ES	7	2	**9**	2	18	**20**	**0**
10_ES	2	1	**3**	5	4	**9**	**2**
11_ES	14	2	**17**	15	9	**24**	**5**
02_ES	5	2	**7**	6	28	**34**	**0**
03_ES	16	0	**16**	3	19	**22**	**11**
04_ES	5	2	**7**	5	5	**10**	**0**
05_ES	13	0	**13**	2	9	**12**	**5**
06_ES	3	1	**4**	13	6	**19**	**4**
07_ES	0	0	**0**	11	4	**15**	**2**
08_ES	2	0	**2**	4	29	**33**	**17**
09_ES	3	1	**4**	9	6	**16**	**4**
74_FI	5	11	**16**	1	13	**14**	**0**
75_FI	18	11	**29**	8	4	**12**	**0**
23_FR	5	0	**5**	20	1	**21**	**0**

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
17_FR	28	4	**32**	7	7	**14**	**0**
21_FR	23	4	**26**	8	6	**14**	**0**
26_FR	20	4	**24**	12	5	**16**	**0**
22_FR	14	4	**17**	3	3	**7**	**0**
27_FR	7	0	**7**	1	2	**3**	**0**
24_FR	13	0	**13**	3	4	**7**	**0**
25_FR	9	0	**9**	8	4	**12**	**0**
20_FR	2	0	**2**	6	13	**19**	**0**
19_FR	5	0	**5**	6	5	**11**	**0**
16_FR	5	1	**6**	9	9	**19**	**5**
15_FR	15	1	**15**	6	15	**20**	**0**
14_FR	4	4	**7**	9	13	**23**	**0**
18_FR	29	0	**29**	6	9	**15**	**0**
99_FR	1	1	**2**	1	4	**4**	**2**
68_GR	4	5	**9**	6	22	**28**	**0**
69_GR	12	9	**22**	11	18	**29**	**11**
62_HR	4	4	**7**	7	11	**18**	**0**
58_HU	6	0	**6**	13	16	**29**	**0**
96_IE	34	11	**45**	9	11	**20**	**0**
53_IT	2	3	**5**	10	5	**15**	**0**
54_IT	2	3	**5**	20	10	**31**	**6**
52_IT	2	3	**5**	44	31	**76**	**0**
55_IT	15	3	**17**	11	8	**19**	**5**
98_IT	5	3	**8**	3	6	**9**	**4**
56_IT	6	3	**9**	8	9	**16**	**5**
77_LT	28	1	**29**	4	6	**10**	**0**

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
29_LU	1	0	**1**	1	0	**1**	**0**
78_LV	20	6	**26**	3	4	**7**	**0**
64_ME	1	0	**1**	1	4	**5**	**0**
67_MK	0	0	**0**	3	9	**12**	**0**
30_NL	18	0	**18**	25	6	**31**	**0**
79_NO	5	0	**5**	1	16	**17**	**0**
80_NO	3	6	**9**	1	16	**17**	**0**
81_NO	4	0	**4**	1	18	**19**	**0**
82_NO	3	6	**8**	3	14	**17**	**0**
83_NO	5	6	**11**	1	19	**20**	**0**
84_NO	9	6	**15**	1	40	**41**	**0**
85_NO	3	6	**8**	0	22	**22**	**0**
41_PL	31	1	**33**	11	8	**19**	**0**
42_PL	26	0	**26**	8	6	**14**	**0**
43_PL	9	0	**9**	12	4	**15**	**0**
44_PL	32	1	**33**	11	7	**18**	**0**
45_PL	27	4	**31**	8	6	**14**	**0**
12_PT	3	2	**5**	8	15	**23**	**9**
13_PT	8	2	**9**	8	4	**11**	**2**
59_RO	0	0	**0**	7	10	**17**	**0**
60_RO	1	0	**1**	11	12	**23**	**0**
61_RO	2	3	**5**	9	10	**19**	**0**
65_RS	2	0	**2**	11	13	**24**	**0**
89_SE	6	0	**6**	3	1	**5**	**0**
88_SE	17	7	**24**	11	7	**18**	**0**
87_SE	10	7	**16**	1	39	**40**	**0**

	Onshore wind potential (GW)	Offshore wind potential (GW)	Total wind potential (GW)	Potential BIPV (GW)	Potential PV farms (GW)	Total PV potential (GW)	CSP potential (GW)
86_SE	8	7	**14**	0	48	**48**	**0**
57_SI	1	0	**1**	3	2	**5**	**0**
46_SK	6	0	**6**	8	5	**13**	**0**
90_UK	23	0	**23**	41	6	**47**	**0**
91_UK	14	8	**23**	10	6	**16**	**0**
92_UK	33	8	**41**	40	22	**62**	**0**
93_UK	23	0	**23**	11	33	**44**	**0**
94_UK	26	0	**26**	6	74	**80**	**0**
95_UK	8	8	**17**	3	7	**10**	**0**
TOTAL	965	212	**1177**	814	1071	**1884**	**97**

Table 54: Potentials per cluster

Annex G: PV distribution keys

PV distribution keys per macro area

Macro area	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
West Europe	30%	26%	27%	26%	31%
South West Europe	7%	23%	22%	22%	14%
Central Europe	10%	11%	13%	12%	21%
North Europe	17%	9%	8%	9%	8%
East Europe	11%	10%	10%	10%	10%
South Europe	5%	22%	21%	21%	16%

Table 55: PV potentials per macro area

PV distribution keys per country

Country	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
AL	7%	3%	6%	7%	2%
AT	20%	13%	18%	19%	10%
BA	4%	3%	4%	4%	2%
BE	5%	7%	5%	5%	8%
BG	18%	11%	17%	17%	10%
CH	19%	13%	18%	18%	11%
CZ	7%	7%	7%	7%	8%
DE	45%	60%	49%	47%	65%
DK	5%	5%	5%	5%	4%
EE	2%	3%	2%	2%	3%
ES	88%	88%	88%	88%	88%
FI	12%	21%	14%	13%	24%
FR	70%	54%	66%	68%	50%
GR	19%	13%	17%	18%	11%

Country	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
HR	2%	3%	3%	2%	3%
HU	17%	15%	17%	17%	14%
IE	0%	2%	1%	1%	3%
IT	61%	71%	63%	62%	74%
LT	3%	6%	4%	3%	8%
LU	0%	0%	0%	0%	0%
LV	2%	5%	3%	3%	6%
ME	2%	1%	2%	2%	1%
MK	1%	1%	1%	1%	1%
NL	4%	9%	6%	5%	11%
NO	51%	40%	48%	50%	37%
PL	21%	33%	24%	22%	36%
PT	12%	12%	12%	12%	12%
RO	30%	21%	27%	29%	16%
RS	3%	4%	4%	3%	5%
SE	37%	39%	38%	38%	39%
SI	3%	2%	3%	3%	2%
SK	6%	6%	6%	6%	7%
UK	21%	27%	22%	22%	28%

Table 56: PV potentials per country

PV distribution keys per cluster

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
70_AL	100%	100%	100%	100%	100%
49_AT	55%	35%	49%	52%	27%
50_AT	27%	30%	28%	27%	32%
51_AT	18%	35%	23%	21%	42%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
63_BA	100%	100%	100%	100%	100%
28_BE	100%	100%	100%	100%	100%
66_BG	100%	100%	100%	100%	100%
47_CH	61%	80%	66%	64%	88%
48_CH	39%	20%	34%	36%	12%
39_CZ	54%	56%	54%	54%	56%
40_CZ	46%	44%	46%	46%	44%
31_DE	14%	17%	15%	14%	18%
32_DE	9%	10%	9%	9%	10%
33_DE	18%	22%	19%	19%	24%
34_DE	11%	11%	11%	11%	11%
35_DE	15%	15%	15%	15%	15%
36_DE	6%	4%	6%	6%	3%
37_DE	27%	21%	25%	26%	19%
38_DK	69%	60%	67%	68%	56%
72_DK	31%	40%	33%	32%	44%
73_EE	100%	100%	100%	100%	100%
01_ES	0%	2%	0%	0%	2%
10_ES	6%	7%	6%	6%	7%
11_ES	8%	15%	10%	9%	18%
02_ES	10%	9%	9%	9%	8%
03_ES	12%	7%	11%	11%	5%
04_ES	4%	6%	4%	4%	6%
05_ES	7%	4%	6%	7%	3%
06_ES	7%	13%	8%	8%	16%
07_ES	11%	13%	11%	11%	14%
08_ES	24%	12%	21%	23%	7%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
09_ES	12%	12%	12%	12%	12%
74_FI	50%	23%	42%	46%	12%
75_FI	50%	77%	58%	54%	88%
23_FR	8%	15%	10%	9%	18%
17_FR	6%	7%	6%	6%	7%
21_FR	0%	5%	2%	1%	7%
26_FR	3%	8%	4%	3%	10%
22_FR	1%	3%	2%	2%	3%
27_FR	1%	1%	1%	1%	1%
24_FR	3%	3%	3%	3%	3%
25_FR	6%	7%	6%	6%	8%
20_FR	13%	8%	12%	12%	6%
19_FR	8%	6%	7%	7%	6%
16_FR	14%	11%	13%	13%	9%
15_FR	12%	8%	11%	12%	6%
14_FR	15%	11%	13%	14%	9%
18_FR	7%	6%	7%	7%	6%
99_FR	3%	1%	3%	3%	1%
68_GR	62%	45%	57%	60%	38%
69_GR	38%	55%	43%	40%	62%
62_HR	100%	100%	100%	100%	100%
58_HU	100%	100%	100%	100%	100%
96_IE	100%	100%	100%	100%	100%
53_IT	8%	9%	8%	8%	10%
54_IT	20%	21%	20%	20%	21%
52_IT	47%	46%	47%	47%	46%
55_IT	11%	11%	11%	11%	11%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
98_IT	4%	3%	4%	4%	3%
56_IT	10%	9%	10%	10%	8%
77_LT	100%	100%	100%	100%	100%
29_LU	100%	100%	100%	100%	100%
78_LV	100%	100%	100%	100%	100%
64_ME	100%	100%	100%	100%	100%
67_MK	100%	100%	100%	100%	100%
30_NL	100%	100%	100%	100%	100%
79_NO	12%	14%	12%	12%	15%
80_NO	12%	13%	12%	12%	13%
81_NO	12%	12%	12%	12%	12%
82_NO	13%	28%	17%	15%	35%
83_NO	12%	12%	12%	12%	11%
84_NO	29%	17%	25%	27%	12%
85_NO	11%	5%	10%	10%	2%
41_PL	21%	22%	22%	22%	23%
42_PL	21%	18%	20%	20%	16%
43_PL	23%	23%	23%	23%	23%
44_PL	25%	23%	25%	25%	22%
45_PL	10%	14%	11%	10%	15%
12_PT	72%	59%	68%	70%	53%
13_PT	28%	41%	32%	30%	47%
59_RO	27%	27%	27%	27%	27%
60_RO	40%	40%	40%	40%	40%
61_RO	33%	33%	33%	33%	33%
65_RS	100%	100%	100%	100%	100%
89_SE	5%	15%	7%	6%	19%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
88_SE	19%	50%	27%	23%	63%
87_SE	32%	18%	28%	30%	12%
86_SE	44%	18%	37%	41%	7%
57_SI	100%	100%	100%	100%	100%
46_SK	100%	100%	100%	100%	100%
90_UK	21%	31%	24%	22%	35%
91_UK	6%	8%	6%	6%	8%
92_UK	27%	33%	28%	28%	35%
93_UK	18%	13%	16%	17%	11%
94_UK	28%	14%	24%	26%	8%
95_UK	1%	2%	1%	1%	3%

Table 57: PV potentials per cluster

Annex H: CSP distribution keys

Macro area and country distribution keys

Macro area	Country	Distribution keys per country within each macro area	Distribution keys per macro area
SWE	**ES**	**82%**	**58%**
	PT	**18%**	
WE	**FR**	**100%**	**4.5%**
SE	**GR**	**39%**	**37.5%**
	IT	**61%**	

Table 58: CSP distribution keys (where DNI > 2000 kWh/m²/y)

Note 1: Distribution keys are set to zero in other countries and macro areas.

Note 2: Distribution keys are independent of the scenario (calculated from constant data such as DNI and area).

Cluster distribution keys

Cluster	Distribution kKey
10_ES	6%
11_ES	11%
03_ES	12%
05_ES	7%
06_ES	5%
07_ES	4%
08_ES	43%
09_ES	12%
16_FR	57%
99_FR	43%
69_GR	100%

Cluster	Distribution kKey
54_IT	23%
55_IT	18%
98_IT	21%
56_IT	38%
12_PT	71%
13_PT	29%

Table 59: Distribution keys CSP per country

Annex I: Wind distribution keys

Wind distribution keys per macro area

Macro area	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
WE	37%	36%	36%	36%	33%
SWE	9%	10%	10%	10%	12%
CE	12%	16%	14%	14%	20%
NE	21%	16%	19%	19%	10%
EE	14%	13%	13%	13%	10%
SE	6%	9%	8%	8%	14%

Table 60: Wind distribution keys per macro area per scenario including North Sea

Macro area	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
WE	30%	31%	31%	30%	32%
SWE	7%	9%	8%	8%	12%
CE	10%	14%	12%	12%	19%
NE	17%	14%	16%	15%	10%
EE	11%	11%	11%	11%	10%
SE	5%	8%	7%	7%	13%
North Sea	19%	13%	16%	17%	3%

Table 61: Wind distribution keys per macro area per scenario without North Sea

Wind distribution keys per country

Macro area	Country	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
WE	**BE**	2%	4%	3%	3%	8%
WE	**IE**	10%	8%	9%	10%	4%
WE	**FR**	33%	37%	36%	34%	45%
WE	**UK**	49%	43%	45%	47%	32%

Macro area	Country	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-10)	Distribution key (X-13)	Distribution key (X-16)
WE	**LU**	0%	0%	0%	0%	0%
WE	**NL**	5%	7%	7%	6%	11%
SWE	**ES**	84%	85%	84%	84%	87%
SWE	**PT**	16%	15%	16%	16%	13%
CE	**AT**	5%	6%	6%	6%	8%
CE	**CH**	1%	4%	2%	2%	8%
CE	**CZ**	6%	7%	6%	6%	7%
CE	**DE**	64%	65%	65%	64%	67%
CE	**DK**	24%	17%	20%	22%	8%
CE	**SI**	0%	1%	0%	0%	1%
NE	**FI**	13%	18%	15%	14%	23%
NE	**NO**	69%	57%	63%	66%	42%
NE	**SE**	18%	25%	22%	20%	35%
EE	**BG**	2%	4%	3%	3%	7%
EE	**EE**	11%	8%	9%	10%	4%
EE	**HU**	4%	7%	6%	5%	12%
EE	**LT**	17%	14%	16%	16%	11%
EE	**LV**	13%	11%	12%	12%	8%
EE	**PL**	49%	46%	47%	48%	39%
EE	**RO**	3%	7%	5%	4%	13%
EE	**SK**	1%	3%	2%	2%	6%
SE	**AL**	2%	2%	2%	2%	2%
SE	**BA**	2%	2%	2%	2%	2%
SE	**GR**	42%	32%	37%	40%	16%
SE	**HR**	4%	4%	4%	4%	4%
SE	**IT**	48%	57%	53%	50%	70%
SE	**MK**	0%	1%	0%	0%	1%
SE	**ME**	0%	0%	0%	0%	0%
SE	**RS**	1%	2%	2%	1%	4%

Table 62: Wind distribution keys per country

Wind distribution keys per cluster

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
70_AL	100%	100%	100%	100%	100%
49_AT	7%	12%	10%	8%	21%
50_AT	15%	21%	18%	16%	29%
51_AT	78%	67%	72%	75%	50%
63_BA	100%	100%	100%	100%	100%
28_BE	100%	100%	100%	100%	100%
66_BG	100%	100%	100%	100%	100%
47_CH	64%	72%	68%	66%	86%
48_CH	36%	28%	32%	34%	14%
39_CZ	36%	43%	39%	38%	53%
40_CZ	64%	57%	61%	62%	47%
31_DE	36%	31%	33%	35%	22%
32_DE	25%	21%	23%	24%	13%
33_DE	12%	16%	14%	13%	22%
34_DE	14%	13%	14%	14%	11%
35_DE	7%	9%	8%	7%	14%
36_DE	1%	2%	1%	1%	3%
37_DE	4%	8%	6%	5%	15%
38_DK	78%	71%	74%	76%	59%
72_DK	22%	29%	26%	24%	41%
73_EE	100%	100%	100%	100%	100%
01_ES	19%	14%	16%	18%	6%
10_ES	4%	5%	5%	4%	7%
11_ES	18%	18%	18%	18%	19%
02_ES	10%	9%	9%	10%	8%
03_ES	14%	11%	12%	13%	6%
04_ES	7%	7%	7%	7%	7%
05_ES	12%	9%	10%	11%	5%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
06_ES	7%	10%	9%	8%	15%
07_ES	1%	6%	4%	3%	12%
08_ES	2%	3%	3%	3%	5%
09_ES	6%	8%	7%	6%	11%
74_FI	23%	18%	20%	22%	11%
75_FI	77%	82%	80%	78%	89%
23_FR	3%	8%	6%	5%	16%
17_FR	14%	12%	13%	14%	8%
21_FR	20%	16%	18%	19%	10%
26_FR	14%	13%	13%	14%	11%
22_FR	12%	9%	10%	11%	5%
27_FR	2%	2%	2%	2%	1%
24_FR	3%	3%	3%	3%	3%
25_FR	3%	4%	4%	3%	7%
20_FR	1%	3%	2%	2%	5%
19_FR	2%	3%	3%	2%	5%
16_FR	4%	5%	5%	4%	8%
15_FR	7%	6%	6%	7%	5%
14_FR	3%	5%	4%	4%	8%
18_FR	11%	9%	10%	11%	7%
99_FR	1%	1%	1%	1%	1%
68_GR	23%	27%	25%	24%	33%
69_GR	77%	73%	75%	76%	67%
62_HR	100%	100%	100%	100%	100%
58_HU	100%	100%	100%	100%	100%
96_IE	100%	100%	100%	100%	100%
53_IT	7%	8%	7%	7%	10%
54_IT	11%	14%	13%	12%	19%
52_IT	7%	20%	14%	10%	39%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
55_IT	33%	26%	29%	31%	15%
98_IT	19%	14%	16%	18%	6%
56_IT	23%	18%	20%	22%	11%
77_LT	100%	100%	100%	100%	100%
29_LU	100%	100%	100%	100%	100%
78_LV	100%	100%	100%	100%	100%
64_ME	100%	100%	100%	100%	100%
67_MK	100%	100%	100%	100%	100%
30_NL	100%	100%	100%	100%	100%
79_NO	11%	12%	11%	11%	14%
80_NO	16%	15%	16%	16%	14%
81_NO	7%	9%	8%	8%	11%
82_NO	17%	24%	21%	19%	34%
83_NO	16%	15%	16%	16%	12%
84_NO	20%	17%	18%	19%	12%
85_NO	12%	9%	10%	11%	3%
41_PL	21%	22%	21%	21%	22%
42_PL	11%	13%	12%	11%	15%
43_PL	7%	12%	10%	8%	20%
44_PL	30%	27%	29%	29%	24%
45_PL	31%	26%	29%	30%	19%
12_PT	30%	37%	34%	32%	47%
13_PT	70%	63%	66%	68%	53%
59_RO	4%	11%	8%	6%	23%
60_RO	12%	21%	17%	14%	35%
61_RO	84%	68%	75%	80%	43%
65_RS	100%	100%	100%	100%	100%
89_SE	9%	12%	11%	10%	18%
88_SE	35%	46%	41%	38%	62%

Cluster	Distribution key (X-5)	Distribution key (X-7)	Distribution key (X-13)	Distribution key (X-10)	Distribution key (X-16)
87_SE	28%	22%	25%	26%	13%
86_SE	29%	20%	24%	26%	7%
57_SI	100%	100%	100%	100%	100%
46_SK	100%	100%	100%	100%	100%
90_UK	17%	23%	20%	18%	33%
91_UK	17%	14%	16%	16%	10%
92_UK	26%	29%	28%	27%	34%
93_UK	13%	12%	13%	13%	11%
94_UK	19%	15%	17%	18%	8%
95_UK	8%	7%	7%	8%	4%

Table 63: Wind distribution keys per cluster

Annex J: Biomass energy potentials

These data are directly computed from the European Bioboost project (except for data for Balkan countries that were provided by EKC)

Clusters	Biomass 1 Potential (GWh)		Clusters	Biomass 1 Potential (GWh)		Clusters	Biomass 1 Potential (GWh)
01_ES	1000		**33_DE**	5632		**65_RS**	11402
02_ES	3188		**34_DE**	7968		**66_BG**	10330
03_ES	4957		**35_DE**	6867		**67_MK**	1801
04_ES	2263		**36_DE**	5655		**68_GR**	3676
05_ES	3675		**37_DE**	8417		**69_GR**	3310
06_ES	2492		**38_DK**	4127		**70_AL**	2483
07_ES	925		**39_CZ**	5046		**72_DK**	2018
08_ES	2830		**40_CZ**	4108		**73_EE**	1764
09_ES	3330		**41_PL**	4188		**74_FI**	3323
10_ES	3673		**42_PL**	4806		**75_FI**	12575
11_ES	3697		**43_PL**	3703		**77_LT**	3116
12_PT	2550		**44_PL**	7656		**78_LV**	3333
13_PT	2647		**45_PL**	5194		**79_NO**	630
14_FR	6438		**46_SK**	5041		**80_NO**	630
15_FR	3832		**47_CH**	1593		**81_NO**	630
16_FR	2826		**48_CH**	464		**82_NO**	630
17_FR	6166		**49_AT**	2124		**83_NO**	630
18_FR	8161		**50_AT**	2634		**84_NO**	630
19_FR	1730		**51_AT**	3563		**85_NO**	630
20_FR	1952		**52_IT**	12248		**86_SE**	2516
21_FR	1487		**53_IT**	5147		**87_SE**	8219
22_FR	1056		**54_IT**	1911		**88_SE**	3896
23_FR	3103		**55_IT**	4554		**89_SE**	1279

Clusters	Biomass 1 Potential (GWh)		Clusters	Biomass 1 Potential (GWh)		Clusters	Biomass 1 Potential (GWh)
24_FR	4644		**56_IT**	2196		**90_UK**	7306
25_FR	3965		**57_SI**	1290		**91_UK**	818
26_FR	6406		**58_HU**	13743		**92_UK**	5501
27_FR	2253		**59_RO**	4811		**93_UK**	2464
28_BE	2826		**60_RO**	7080		**94_UK**	2250
29_LU	111		**61_RO**	7043		**95_UK**	177
30_NL	3751		**62_HR**	4678		**96_IE**	833
31_DE	6746		**63_BA**	4701		**98_IT**	594
32_DE	9026		**64_ME**	1003		**99_FR**	585

Table 64: Biomass potentials per cluster

Annex K: Modelling parameters of thermal plants

Modelling parameters for thermal units

	Rated power (MW)	Minimum stable power (MW)	Min up/down time (hours)	Forced outage rate (%)	Planned outage rate (%)	Outage duration (days)	CO_2 emissions (t/MWh)
Nuclear	1600	800	168	5	15	7	0
Hard coal without CCS	800	320	6	5	15	7	0,644
Hard coal with CCS	800	320	24	5	15	7	0,084
Lignite without CCS	800	320	24	5	15	7	0,767
Lignite with CCS	800	320	24	5	15	7	0,045
CCGT without CCS	500	150	3	5	15	7	0,327
CCGT with CCS	500	150	24	5	15	7	0,017

	Rated power (MW)	Minimum stable power (MW)	Min up/down time (hours)	Forced outage rate (%)	Planned outage rate (%)	Outage duration (days)	CO_2 emissions (t/MWh)
OCGT	250	150	3	5	15	7	0,488
Biomass 1	250	150	3	5	15	7	0
Biomass 2	250	150	3	5	15	7	0

Table 65: Modelling parameters for thermal units - Source: WP3 and TSO experience

Costs for system simulations

According to projections of fuels prices, O&M costs, investment costs and CO_2 price, the following marginal costs are used for system simulations with Antares:

Marginal costs for system simulations (€/MWh)					
	X-5	**X-7**	**X-10**	**X-13**	**X-16**
OCGT	189	203	172	172	203
CCGT without CCS	131	not considered	118	118	141
CCGT with CCS	not considered	not considered	46	46	not considered
Coal without CCS	180	not considered	not considered	not considered	196
Coal with CCS	not considered	not considered	47	47	not considered
Lignite without CCS	180	not considered	not considered	not considered	200
Lignite with CCS	not considered	not considered	29	29	not considered
Nuclear	14	not considered	14	14	14
Biomass1	20	10	20	20	10
Biomass2	135	20	135	135	20

Table 66: Fuels prices, O&M costs, investment costs and CO_2 price for thermal units

NB: the very high prices of fossil units without CCS is due to the high cost of CO_2 assumed (270€/t)

Annex L: Installed Capacities by technology per country and scenario including hydro power

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Hydro Power		Demand (GWh)	Balance (%)
						RoR (GWh)	Reservoir + PSP (MW)		
AL	2.421	850	0	0	0	6.820	2.728	15.030	121,00%
AT	6.875	7.226	1.250	0	5.250	44.419	14.620	93.481	94,00%
BA	2.599	921	250	0	0	13.349	2.323	15.545	175,00%
BE	10.901	8.421	3.500	0	18.500	1.793	2.308	148.476	51,00%
BG	4.403	3.296	1.750	1.600	2.300	5.802	9.709	38.990	115,00%
CH	1.382	10.500	1.250	0	3.500	19.604	13.573	81.731	77,00%
CZ	10.279	3.925	500	11.200	3.800	2.080	2.308	87.873	120,00%
DE	98.600	54.428	9.000	0	45.000	24.700	10.666	815.155	44,00%
DK	18.492	2.606	3.000	0	2.250	70	0	52.246	131,00%
EE	8.244	409	250	0	1.000	263	659	15.292	133,00%
ES	67.448	50.822	6.000	8.000	31.800	35.895	30.556	609.826	70,00%

FI	37.198	1.505	3.000	3.200	3.000	8.339	2.231	101.119	139,00%
FR	84.219	33.090	6.750	72.000	17.300	56.576	29.384	795.247	106,00%
GR	25.861	8.266	1.500	0	1.000	3.358	9.026	83.072	126,00%
HR	6.255	882	250	0	1.000	2.981	4.532	29.295	79,00%
HU	4.889	3.127	2.500	6.400	2.000	4.590	791	72.459	102,00%
IE	15.479	258	500	0	6.250	1.091	1.589	52.759	105,00%
IT	41.293	30.252	5.500	0	41.900	23.870	19.667	528.236	48,00%
LT	14.959	529	750	1.600	2.500	1.194	1.489	34.344	148,00%
LU	617	121	250	0	1.000	950	1.376	9.041	53,00%
LV	13.709	425	750	0	1.000	4.000	0	25.690	146,00%
ME	520	616	0	0	0	1.096	3.649	3.943	287,00%
MK	371	443	0	0	500	0	1.776	10.333	63,00%
NL	14.993	6.173	3.000	1.600	23.300	732	0	196.805	46,00%
NO	13.048	480	250	0	500	61.570	54.173	124.918	194,00%
PL	62.521	3.807	4.750	9.600	5.800	12.000	3.158	210.883	97,00%
PT	11.474	5.544	1.000	0	4.750	14.539	7.676	86.870	86,00%
RO	4.818	5.404	3.250	4.800	4.300	29.945	8.361	83.587	120,00%

RS	1.429	1.235	250	0	2.800	15.633	1.683	38.439	60,00%
SE	35.689	1.624	3.000	6.400	500	13.857	17.693	146.446	143,00%
SI	472	1.739	250	2.000	500	8.800	264	18.294	144,00%
SK	4.697	1.004	1.000	3.200	1.000	6.607	256	32.497	119,00%
UK	83.587	6.386	4.500	25.600	33.550	4.680	10.570	537.632	99,00%

Table 67: Final installed capacities by technologies and balances on country level including hydro power – X-5

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Peak – Units (MW)	Hydro Power		Demand (GWh)	Balance (%)
					RoR (GWh)	Reservoir + PSP (MW)		
AL	2.433	1.181	0	0	7.457	2.983	15.030	135,00%
AT	6.880	12.090	3.500	1.500	44.419	16.409	84.825	98,00%
BA	2.599	1.291	250	0	14.595	2.602	12.695	226,00%
BE	10.903	24.087	4.750	2.500	1.793	2.308	121.255	47,00%
BG	4.403	5.395	4.750	0	5.802	9.956	31.842	114,00%
CH	1.382	15.000	1.250	2.000	19.604	13.573	77.330	77,00%
CZ	10.234	13.048	5.000	1.750	2.080	2.606	71.763	67,00%
DE	98.326	98.599	27.750	13.000	24.700	12.799	665.705	57,00%
DK	18.708	2.038	3.750	1.000	70	0	42.667	146,00%
EE	8.141	803	1.000	250	338	791	12.488	160,00%
ES	69.383	102.523	17.250	8.500	38.055	33.973	498.020	86,00%
FI	29.531	5.835	3.750	1.250	8.907	2.383	82.580	125,00%
FR	124.197	106.905	28.250	16.000	56.576	31.620	649.447	86,00%
GR	25.851	15.068	3.750	0	3.672	10.090	67.841	170,00%

HR	6.254	3.782	0	0	3.259	4.996	23.924	104,00%
HU	4.897	13.997	7.250	0	4.590	949	59.428	80,00%
IE	13.628	3.836	250	2.000	1.091	1.907	43.086	107,00%
IT	41.290	101.044	14.750	9.000	26.098	21.978	431.389	76,00%
LT	15.163	1.343	1.750	500	1.194	1.787	28.047	135,00%
LU	739	1.030	0	250	950	1.651	7.383	45,00%
LV	13.811	1.133	1.750	500	4.000	0	20.980	179,00%
ME	520	490	0	0	1.198	3.990	3.220	381,00%
MK	371	1.374	0	0	0	1.942	8.438	92,00%
NL	14.997	22.247	4.000	3.000	732	0	160.723	47,00%
NO	12.175	5.364	500	0	65.765	59.764	102.015	242,00%
PL	81.918	24.220	14.250	3.000	12.000	3.790	172.220	112,00%
PT	11.861	13.805	2.750	0	14.625	8.650	70.943	112,00%
RO	4.828	10.980	9.250	0	29.945	8.617	68.262	111,00%
RS	1.431	4.986	1.000	0	17.092	1.926	31.392	83,00%
SE	24.211	8.919	5.500	0	13.857	21.383	131.557	125,00%
SI	472	2.332	750	250	8.800	316	14.940	92,00%
SK	5.230	6.880	2.750	500	6.607	307	26.539	98,00%

UK	93.112	59.896	12.500	6.500	4.680	11.636	439.063	97%

Table 68: Final installed capacities by technologies and balances on country level including hydro power – X-7

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Hydro Power		Demand (GWh)	Balance (%)
						RoR (GWh)	Reservoir + PSP (MW)		
AL	478	1.000	0	0	1.500	2.573	1.029	15.030	84,00%
AT	5.751	7.040	1.250	0	3.500	32.761	10.974	84.023	92,00%
BA	767	1.775	0	0	1.300	3.634	915	12.996	113,00%
BE	6.899	5.182	2.500	0	21.250	1.739	1.308	121.165	71,00%
BG	1.811	3.723	750	1.600	3.050	1.926	3.750	33.660	110,00%
CH	1.382	9.825	1.500	0	5.250	18.250	13.011	77.318	92,00%
CZ	6.155	4.072	1.000	8.000	500	1.501	1.721	70.698	116,00%
DE	70.844	51.753	9.000	0	62.100	24.309	8.095	660.937	64,00%
DK	10.951	1.591	3.000	0	500	21	0	39.080	108,00%
EE	5.412	538	250	0	500	46	500	12.367	122,00%
ES	44.351	57.798	5.000	8.000	30.050	20.278	19.452	529.401	79,00%
FI	10.859	569	3.000	3.200	8.150	6.468	1.731	83.528	109,00%
FR	57.780	40.366	7.750	48.000	17.050	45.496	23.124	657.057	104,00%
GR	15.565	10.352	1.000	0	3.000	857	3.347	67.315	108,00%
HR	1.822	1.299	0	0	2.550	1.784	2.774	23.584	77,00%

HU	3.481	3.787	1.250	3.200	4.000	227	600	59.548	91,00%
IE	12.303	558	250	0	1.750	841	1.206	41.871	104,00%
IT	22.348	44.729	8.000	0	52.350	19.082	15.542	435.969	81,00%
LT	7.474	902	500	1.600	3.250	1.194	1.130	29.594	137,00%
LU	280	171	0	0	1.000	941	1.044	7.591	57,00%
LV	6.848	699	500	0	1.750	3.581	0	21.769	122,00%
ME	106	458	0	0	500	192	638	3.380	73,00%
MK	196	617	0	0	1.800	0	415	8.839	112,00%
NL	12.198	5.362	2.750	0	29.950	126	0	170.422	66,00%
NO	6.261	1.303	750	0	0	38.579	35.852	111.578	139,00%
PL	27.180	5.386	2.750	8.000	6.150	3.131	2.397	159.877	92,00%
PT	8.179	7.555	1.000	0	6.000	7.940	5.210	75.353	103,00%
RO	4.000	6.159	1.500	3.200	7.350	12.312	3.882	63.961	124,00%
RS	757	1.819	250	0	3.900	9.763	1.160	32.390	105,00%
SE	9.146	1.527	2.750	8.000	1.000	13.857	13.259	139.275	116,00%
SI	382	1.651	250	1.000	500	4.550	200	14.373	111,00%
SK	1.232	1.308	500	1.600	1.750	4.561	194	28.190	95,00%
UK	73.105	9.409	4.250	20.800	14.850	2.429	6.765	388.699	118%

Table 69: Installed capacities by technologies and balances on country level including hydro power – X-10

Country	Wind (MW)	Solar [PV + CSP] (MW)	Biomass (MW)	Nuclear (MW)	Thermal (MW)	Hydro Power		Demand (GWh)	Balance (%)
						RoR (GWh)	Reservoir + PSP (MW)		
AL	224	368	0	0	1.000	2.573	1.029	15.030	121,0%
AT	2.985	7.327	1.250	0	5.800	32.761	10.974	88.317	94,0%
BA	345	587	0	0	1.300	3.634	915	14.379	175,0%
BE	4.320	4.045	2.500	0	21.500	1.739	1.308	134.061	51,0%
BG	1.440	679	500	3.200	1.800	1.926	3.750	37.242	115,0%
CH	627	6.449	1.250	0	7.000	18.250	13.011	74.854	77,0%
CZ	2.547	2.550	500	8.000	6.700	1.501	1.721	78.223	120,0%
DE	45.749	51.753	8.250	0	80.700	24.309	8.095	731.280	44,0%
DK	8.908	1.646	3.000	0	2.300	21	0	43.240	131,0%
EE	3.009	290	250	0	1.000	46	500	13.683	133,0%
ES	38.000	40.967	4.000	8.000	46.900	20.278	19.452	585.745	70,0%
FI	3.861	954	3.000	6.400	6.500	7.187	1.923	92.417	139,0%
FR	22.397	9.976	8.000	83.200	17.600	45.496	23.124	726.987	106,0%
GR	7.604	3.306	750	0	9.000	857	3.347	74.479	126,0%
HR	842	2.728	0	0	3.300	1.784	2.774	26.094	79,0%
HU	1.530	2.133	750	6.400	4.500	227	600	65.886	102,0%

IE	8.223	224	250	0	5.500	841	1.206	46.328	105,0%
IT	15.028	28.310	4.500	0	64.800	19.082	15.542	482.369	48,0%
LT	4.050	433	250	1.600	3.000	1.194	1.130	32.744	148,0%
LU	131	113	0	0	500	941	1.044	8.399	53,0%
LV	3.717	341	250	0	2.000	3.581	0	24.086	146,0%
ME	46	458	0	0	800	192	638	3.740	287,0%
MK	110	357	0	0	1.800	0	415	9.779	63,0%
NL	11.178	1.560	1.000	0	31.100	126	0	188.560	46,0%
NO	5.031	2.489	750	0	0	42.866	38.620	123.454	194,0%
PL	14.344	2.787	2.500	9.600	10.800	3.131	2.397	176.893	97,0%
PT	6.875	6.000	500	0	8.500	7.940	5.210	83.373	86,0%
RO	4.000	3.577	1.000	3.200	7.700	12.312	3.882	70.768	120,0%
RS	279	1.022	250	0	2.600	9.763	1.160	35.837	60,0%
SE	4.547	2.813	3.000	8.000	1.500	13.857	14.732	140.089	143,0%
SI	111	1.091	250	1.000	500	4.550	200	15.903	144,0%
SK	486	711	250	3.200	1.500	4.561	194	31.190	119,00%
UK	39.247	6.977	3.750	27.200	41.500	2.429	6.765	430.068	99,0%

Table 70 Final installed capacities by technologies and balances on country level including hydro power – X-13

Country	Wind	Solar [PV + CSP]	Biomass	Nuclear	Thermal	Hydro Power		Demand	Balance (%)
						RoR (GWh)	Reservoir + PSP (MW)		
AL	529	2.351	0	0	1.000	2.573	1.029	15.030	71%
AT	2.578	2.827	1.250	0	1.000	32.761	10.974	60.170	97%
BA	1.121	1.016	0	0	750	3.634	915	9.979	99%
BE	10.915	21.052	6.500	0	6.500	1.793	1.308	87.794	102%
BG	2.771	3.805	2.250	0	0	1.926	3.750	26.193	97%
CH	1.381	15.000	1.500	0	250	18.250	13.011	60.274	106%
CZ	3.147	4.469	1.750	4.800	5.000	1.501	1.721	52.818	113%
DE	85.419	109.275	15.000	0	17.600	24.309	8.095	466.152	89%
DK	4.928	69	2.500	0	1.000	21	0	28.656	97%
EE	2.063	1.449	500	0	1.000	46	500	9.113	101%
ES	39.141	87.300	9.750	3.200	16.000	20.278	19.452	363.178	100%
FI	2.500	10	3.000	6.400	250	7.187	1.923	66.059	112%
FR	53.678	77.098	16.000	14.400	10.500	45.496	23.124	479.001	100%
GR	9.085	8.414	2.250	0	7.000	857	3.347	50.684	121%
HR	2.042	4.085	250	0	500	1.784	2.774	16.880	98%
HU	4.534	3.979	4.000	1.600	3.500	227	600	42.354	110%

IE	6.635	4.080	500	0	4.000	841	1.206	28.392	107%
IT	39.031	108.833	7.750	0	8.500	19.082	15.542	364.255	94%
LT	3.267	2.959	750	1.600	1.000	1.194	1.130	22.250	114%
LU	540	904	500	0	1.000	941	1.044	5.362	107%
LV	2.910	3.071	1.250	0	2.500	3.581	0	16.108	121%
ME	183	388	0	0	0	192	638	2.562	95%
MK	372	2.438	250	0	500	0	415	6.576	111%
NL	14.531	31.565	4.500	1.600	7.000	126	0	117.963	98%
NO	3.535	0	500	0	0	42.866	38.620	91.514	162%
PL	14.798	19.561	7.000	1.600	2.500	3.131	2.397	114.220	86%
PT	6.875	9.098	1.500	0	3.000	7.940	5.210	51.027	114%
RO	4.737	1.022	3.000	1.600	3.000	12.312	3.882	45.627	118%
RS	1.430	4.021	750	0	3.800	9.763	1.160	24.986	98%
SE	6.813	4.222	5.500	0	0	13.857	14.732	109.416	107%
SI	283	2.928	500	0	500	4.550	200	10.914	111%
SK	2.118	3.263	1.500	0	500	4.561	194	20.353	92%
UK	38.985	43.347	5.500	11.200	17.000	2.429	6.765	321.117	95%

Table 71: Final installed capacities by technologies and balances on country level including hydro power – X-16

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