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# Effect of electromobility on the power system and the integration of RES

S13 Report

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# 1. EXECUTIVE SUMMARY

In the coming years and decades, the number of electric vehicles (battery electric and plug-in hybrid vehicles) will substantially increase, according to the EU EUCO30[1] scenario that projects reaching the 2030 EU energy and climate targets and $CO_2$ standards for cars and vans getting progressively more stringent. Namely, the stock of electric vehicles in EU28 countries could rise from less than 1 million [1] electric cars today, to more than 35 million in 2030 and around 190 million in 2050, according to projections[2]. In this scenario, by 2050 up to 34% of all final energy demand in passenger car transport could be electric. The related additional electricity demand (about 356 TWh) would increase overall EU electricity demand by 10%[3]. If electric vehicle batteries are charged without any strategy, this may result in an increase of expected energy not served by the power system or the need for additional peak load capacities. At the same time, an optimized charging strategy may represent an additional flexibility for the power system and thus facilitate the integration of variable renewable energy sources and bring down power generation costs.

The objective of the study is to better understand the implications related to the increasing share of electric vehicles for the power system. Different electric vehicle charging strategies are evaluated in terms of power system impacts. The assessment is realised with the EU power system model METIS, which was further extended in order to adequately simulate the potential interaction between large electric vehicle fleets and the power system. Hence, the study also illustrates the additional capabilities of the extended METIS tool.

As the integration of electric vehicles in the EU power system represents a complex topic that can be analysed under varying aspects, the scope of the study is subject to a set of limitations and simplifying assumptions. For instance, the analysis focusses exclusively on the day-ahead market, without taking into account potential interaction with other market segments, such as intraday or reserve markets. As the projection horizon of the analysis lasts until the year 2050, technology and behavioural assumptions are subject to high uncertainty. Future driving patterns are difficult to predict as new car ownership and driving concepts (e.g. car sharing, autonomous vehicles) are likely to enter the market. In the current study, it is assumed that driving patterns remain unchanged. In the context of vehicle-to-grid concepts, technology progress is supposed to offset the impact of an increased number of battery charging cycles on battery aging by the year 2030. At the same time, in order to account for psychological barriers, a constraint is added that electric vehicles can only leave the charging station once the battery is fully charged.

The study consists of two major parts. An initial literature review reveals that the design of appropriate electric vehicle integration measures depends on the level of electric vehicle penetration. At a low degree of electric vehicle penetration, no load management and thus no dedicated policies are necessary. An increasing electric vehicle penetration requires the

[1] The 'EUCO30' scenario has been developed to reach all the 2030 targets agreed by the October 2014 European Council (at least 40% reduction in greenhouse gas emissions with respect to 1990, 27% share of RES in final energy consumption and 30% reduction in the primary energy consumption) and the 2050 decarbonisation objectives, continuing and intensifying the current policy mix. The 'EUCO' scenario has been developed by ICCS-E3MLab with the PRIMES energy system model.

[2] The model takes into account different size classes for vehicles. Therefore, it accounts for the differences by vehicle size class in terms of specific fuel consumption. On average, the specific fuel consumption of a BEV is projected to be one third of that of a conventional internal combustion engine car in 2050.

[3] The study only covers passenger cars. However, the electricity use by passenger cars is projected to represent about 87% of all electricity use in road transport by 2050.

introduction of load management schemes, which may require an adaptation of existing policies. Such policies potentially could facilitate the introduction of time-varying tariffs giving incentives for a modified charging behaviour. In the modelling, assuming competitive markets and the incentives to charge in a smart way which will gradually be introduced *inter alia* in line with the new market design rules proposed in the Clean Energy Package[4], the negative effects of additional load can be avoided and integration of variable renewable energy sources might be facilitated by flexibility provided from electric vehicles.

The subsequent model-based assessments with the METIS tool provide an in-depth analysis of the different derived charging strategies. They are carried out in three parts, cf. Figure 1.1, and are assessed according to five major key performance indicators – expected energy not served, peak load, marginal costs, $CO_2$ emissions and curtailment.

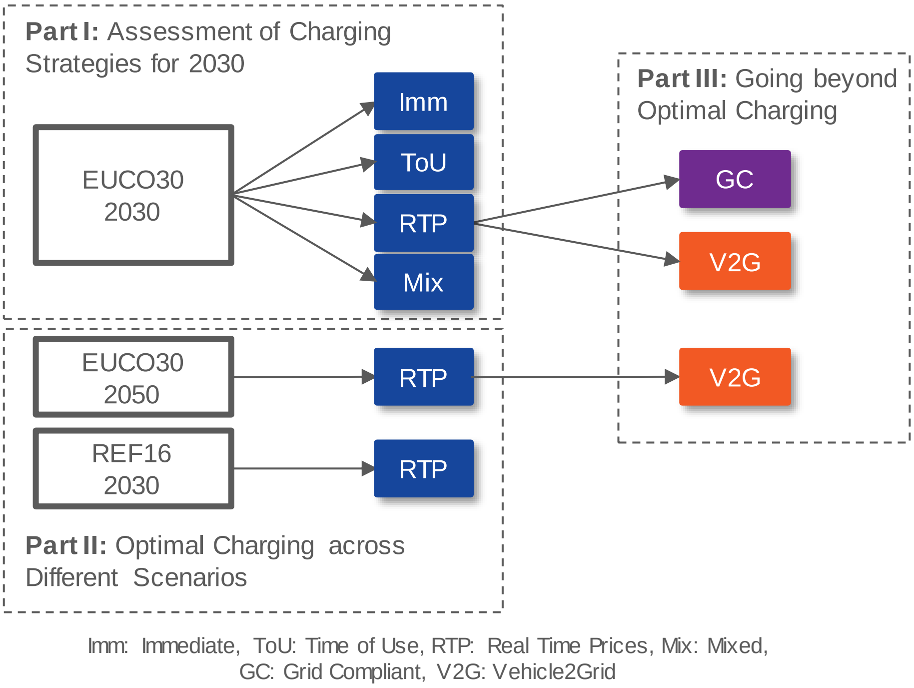



*Figure 1.1 : Overview on dimensions to be investigated*

1. **PART I: Comparison of different charging strategies for a single scenario (EUCO30) in 2030**

   The different charging strategies include **immediate, time-of-use- and real-time price-based charging**.

   While the **immediate charging** represents a charging immediately after arrival, the charging behaviour for time-of-use- and real-time price-based charging is incentivised by price signals. The charging peak related to immediate charging creates system load peaks in EUCO30 scenario in 2030 due to the charging in hours of high residual load (primarily in morning and early evening hours). This implies risks of energy not served and congestion in the grids, if no peak power or additional storage capacities are added, and if there are no measures foreseen to address grid congestion.

[4] Thus moving from the current practice in many Member States where fixed tariff pricing is common.

Going from immediate to **time-of-use-based charging** (where the costumer is incentivised to charge in times of low load through a price signal that varies over the course of the day but is static over the time) allows to avoid a further increase of the evening peak in residual load compared to immediate charging. The underlying time-of-use-tariff – which could consist of two price periods per day or more - thus reduces the risk of expected energy not served significantly. Furthermore, the utilisation of expensive peak load capacities can be limited, which results in lower marginal power generation costs (- 14%). Hence, in the long term the question is not "if" electric vehicles need to be integrated in a smart manner", but rather "how".

While time-of-use-based charging mitigates the worst effects of uncoordinated charging, **real-time price-based charging** (where customers can optimize their charging behaviour in hourly resolution based on real-time prices) provides an additional reduction in marginal costs of –27% compared to time-of-use-based charging. Real-time price-based charging further decreases the utilisation of expensive peak load capacities and making enhanced use of base-load capacities. Furthermore, the production costs[5] can be reduced by 728.1 Mio. € (- 1.1%) for real-time price-based charging compared to uncoordinated (immediate) charging. Next to the cost reduction considering the overall power system, EV owners can also benefit from savings in power purchase costs to a varying extent (e.g. about 13% savings for RTP-based compared to immediate charging in Italy).

Finally, a mixed scenario was developed, assuming that not all electric vehicle owners (but only 50% of them) will adapt their charging behaviour to real-time prices. This scenario brings benefits in the range between time-of-use-based and real-time price-based charging.

## 2. PART II: Real-time price-based charging in different scenarios and time horizons

The assessment in Part II focusses on real-time price-based charging in three different scenarios: REF16[6] in 2030 (42.6% overall share of renewables in net electricity generation, electric vehicles representing around 1% of total EU electricity demand), EUCO30 in 2030 (49.5% overall share of renewables, electric vehicles representing 2% of total electricity demand) and EUCO30 in 2050 (64.4% overall share of renewables, electric vehicles representing around 10% of total electricity demand). In 2030, electric vehicles will still play a limited role, but by 2050 they will represent an important share of the car fleet, with the share of electricity in energy demand for passenger cars reaching 34%.

The benefits of real-time price-based charging in EUCO30 in 2030 compared to the base scenario[7] are described above. The REF16 scenario in 2030 is rather conservative in terms of electricity use in passenger cars compared to the EUCO30 scenario for the same year; this is because only policies already in place are reflected in REF16. Thus,

[5] Production costs do not include battery costs as well as costs for installation of new generation capacities but are limited to costs related to fuel purchase and $CO_2$ emission allowances.

[6] The EU Reference Scenario 2016 (REF16) provides developments under current trends and adopted policies. It assumes that the climate and energy legally binding targets for 2020 will be achieved and that the policies agreed at EU and Member State level until December 2014 will be implemented.

[7] Base scenario: Integration of electric vehicle demand in national load curves from ENTSO-E TYNDP without a distinct representation of the charging pattern (c.f. Section 5.2). Please note that the carbon market is not explicitly modelled in the METIS model and a constant $CO_2$ price is assumed.

the benefits from smart electric vehicle integration are limited. In EUCO30 in 2050, taking also into account the higher $CO_2$ price, the shift in electric vehicle charging demand does not only reduce the need for peak load capacities but goes along with a drop in $CO_2$ emissions (-8%) from power generation compared to the base scenario, as the merit order is headed by RES, biomass and gas-fuelled power generation capacities. At the same time the mean marginal costs across the EU are reduced by around 12% in 2050 compared to the base scenario.

## 3. PART III: Real-time price-based charging with additional options, namely vehicle-to-grid (V2G) and grid compliant charging

**Real-time price-based charging with V2G option** *(=bi-directional power flows between the electric vehicle and the grid based on real-time prices)*

The ability of electric vehicles to feed electricity from the batteries back into the grid, as considered in the vehicle-to-grid scenario, adds storage capacities to the power system and therefore facilitates variable renewable energy sources integration. This can be observed in EUCO30 in 2050 by a reduction of curtailment (by nearly 20% in 2050) compared to the same scenario without vehicle-to-grid incentives. In addition, vehicle-to-grid benefits the base load capacities and reduces costs as well as $CO_2$ emissions from power generation (-2.6% compared to the scenario without vehicle-to-grid) in EUCO30 in 2050. Compared to the reduction of production costs of real-time price-based in 2030, the production costs are further reduced by some 182 million € or 0.3%. In sum, this means a reduction of production costs of 910 m € for a real-time pricing scheme with vehicle-to-grid option compared to immediate charging option.

***Optimal charging which is respectful of grid constraints*** *(=charging based on real-time prices with caps on cumulated vehicle charging load to prevent the stress on the grid)*

As real-time price-based charging may further increase existing load peaks compared to the base scenario (e.g.in Italy), it may make sense to cap simultaneous electric vehicle charging (in the following referred to as grid compliant charging) in order to protect distribution and transmission grids from additional stress. Grid compliant charging might reduce new system load peaks and thus limit the need for additional grid reinforcement. Yet, to obtain some comprehensive insights it is necessary to carry out a detailed grid modelling. Thereby, it can be assessed whether it is better to rather reinforce grid capacities and allow for a pure market-based optimization or whether grid aspects should be included into the tariff-signal that serves for electric vehicle charging optimization.

**Resulting policy recommendations**

1. Negative impacts resulting from uncoordinated charging while electric vehicle penetration increases can be avoided by introducing time-varying tariffs like time-of-use or real-time prices. This recommendation is fully in line with Article 11 of the proposed recast of the Electricity Market Directive (COM(2016) 864 final/2, [16]), enabling consumers direct participation in the market via dynamic electricity pricing contracts. These schemes are recommended to be established as insurance policy that the system can cope when the electric passenger cars are deployed on large scale.

2. To capture the full benefits of additional system flexibility created by electric vehicles and ensure a fully system-compliant integration, place should be given to new actors, such as aggregators that can bundle the shiftable load of all flexible consumers and/or to establish real-time pricing for final costumers themselves. This echoes the relevance of paving the way for aggregators, as required from Member States through Article 17 of the proposed recast of the Electricity Market Directive [16].
3. As time-of-use-/real-time price-based electric vehicle charging requires communication and data flow between the consumer and the suppliers or aggregators as well as grid operators, it is important to ensure an enabling framework and acceptability for such new IT technologies, e.g. by
    - ensuring necessary roll-out metering and IT technologies and
    - ensuring the establishment of secure data exchange and storage in order to address consumers' privacy and data protection concerns.

   Article 19 and 20 of the proposed recast of the Electricity Market Directive [16] take this line by calling for a comprehensive implementation of smart metering systems compliant with a set of pre-defined functionalities as well as specific levels of cybersecurity protection.
4. Electric vehicle smart charging should finally not only be considered as a means of reasonable integration of electric vehicles in the power system, but as a resource of system flexibility (e.g. for RES integration) by making use of the batteries installed in electric vehicles as important system storage potential. Paving the way for battery utilisation for system services via vehicle-to-grid technology requires dedicated IT-based communication and management solutions as well as access for electric vehicle owners or intermediary entities to the respective markets for system services. The proposed recast of the Electricity Market Regulation (COM(2016) 861 final/2, [17]) backs this development by calling for enhanced investments in infrastructure supporting the integration of variable and distributed generation. It further calls for effective scarcity prices that encourage market participants to be available when flexibility is most needed in the power system.
5. As purely electricity-price-based optimization of charging behaviour entails the risks of enhanced stress situations for distribution and transmission grids, the benefits from smart electric vehicle charging need to be contrasted with related grid reinforcement requirements. Grid constraints could be taken into account in time varying tariffs e.g. via time-varying network charges. The relevant possibility is clearly spelled out in the proposed recast of the Electricity Market Directive, but its actual use will depend on decisions of individual Member States.

# 2. ABBREVIATIONS

| Abbreviation | Definition |
|---|---|
| BEV | Battery Electric Vehicle |
| CM | Constraint Management |
| CCGT | Combined Cycle Gas Turbine |
| DSO | Distribution System Operator |
| EC | European Commission |
| EENS | Expected Energy not Served |
| EV | Electric Vehicle (covering BEV and PHEV) |
| EVSE | Electric Vehicle Supply Equipment |
| EVSP | Electric Vehicle Service Provider |
| GC | Grid Compliant |
| OCGT | Open Cycle Gas Turbine |
| PHEV | Plug-in-Hybrid Electric Vehicle |
| PV | Photovoltaics |
| RES | Renewable Energy Sources |
| RTP | Real-Time Price(s) |
| ToU | Time-of-Use |
| V2G | Vehicle to Grid |

# 3. INTRODUCTION AND OBJECTIVE OF THE STUDY

The electrification of passenger road transport is projected to gain significant momentum during the next decades, driven by the shift towards low emission mobility [2]. This change will imply an additional electricity demand from the transport sector that needs to be met by the power system. The increasing number of electric vehicles (EV) may not only change the overall demand volume but also the shape of the hourly load curve of the power system and entail significant challenges for electricity generation, transmission and distribution infrastructure [3]. Studies so far indicate that by coordinating the charging process, the impact of electrifying the entire fleet of cars could be managed: EV could provide flexibility to the power system and investments in infrastructure upgrades could be minimized. Smart charging of car batteries could help to smooth the load curve, which in turn may result in lower electricity prices compared to uncoordinated charging.

The determination of the flexibility related to EV charging and the possible impacts on the power system requires a comprehensive understanding of the complex relations as well as interdependencies between changes in the load curve and resulting changes for the power system. This leads to the question, how these relations and interdependencies can be modelled to assess the impact on the power system. In order to do so, different EV charging strategies are evaluated in order to determine how risks related to EV penetration can be prevented and transformed into system benefits in terms of power system impacts. The assessment is realised with the EU power system model METIS, which was further extended in order to adequately simulate the potential interaction between large electric vehicle fleets and the power system. Hence, the study has also for purpose to illustrate the additional capabilities of the extended METIS tool.

As the integration of electric vehicles in the EU power system represents a complex topic that can be analysed under varying aspects, the scope of the study is subject to a set of limitations and simplifying assumptions. For instance, the analysis focusses exclusively on the day-ahead market, without taking into account potential interaction with other market segments, such as intraday or reserve markets. As the projection horizon of the analysis lasts until the year 2050, technology and behavioural assumptions are subject to high uncertainty. Future driving patterns are difficult to predict as new car ownership and driving concepts (e.g. car sharing, autonomous vehicles) are likely to enter the market. In this study, it is assumed that driving patterns remain unchanged.

To answer these questions, the study is separated into two major parts, a literature-based and a model-based scenario analysis. As a part of the literature-based analysis, theoretical basics for subsequent assessments are gathered. For the introduction of the different charging strategies and the terminologies used in this study, Section 4 of this report presents the results of the literature-based analysis by introducing different smart charging implementation stages [4]. Based on this analysis, the smart charging strategies that are to be investigated in the scenario analysis are derived. Section 5 shows the implementation of these charging strategies. In Section 6, the scope of the assessments as well as the assessment results are presented. Finally, Section 7 presents the conclusion of the study results.

The study covers EU28 as well as six neighbouring countries (Norway, Switzerland, Bosnia and Herzegovina, Serbia, FYROM, and Montenegro).

### 3.1. Modelling Setup

| SETUP | |
|---|---|
| METIS version used | METIS v1.1 |
| Modules Used | Power system module |
| Scenarios used[8] | EuCo30 for the year 2030, EuCo30 for the year 2050, REF16 for the year 2030 |
| Time granularity | Hourly (8760 consecutive time-steps per year) |
| Spatial granularity | Member State |
| Charging strategies | Different strategies studied |

[8] The EU Reference Scenario 2016 (REF16) provides developments under current trends and adopted policies. It assumes that the climate and energy legally binding targets for 2020 will be achieved and that the policies agreed at EU and Member State level until December 2014 will be implemented. Building on the REF16, the 'EUCO30' scenario has been developed to reach all the 2030 targets agreed by the October 2014 European Council (at least 40% reduction in greenhouse gas emissions with respect to 1990, 27% share of RES in final energy consumption and 30% reduction in the primary energy consumption) and the 2050 decarbonisation objectives, continuing and intensifying the current policy mix. The 'REF16' and 'EUCO' scenarios have been developed by ICCS-E3MLab with the PRIMES energy system model.

# 4. Determination of Charging Strategies

As part of the assessment of future scenarios regarding the influence of a higher share of electromobility, a literature-based analysis is carried out that prepares the ground for the subsequent model-based assessment. In the first part of this section, different *smart charging implementation stages*, defined by the level of EV integration, from the literature will be described [4]. They outline the level of EV integration into the energy system and the related developments concerning technology and regulatory framework in the energy sector. The implementation stages serve as basis to derive the three charging strategies that are subject to the in-depth model-based assessment.

## 4.1. Literature-Based Analysis

Smart charging implementation stages determine the level of integration of EV into the power system. There are different stages given in literature which describe the possible developments concerning the technology and the regulatory framework in the energy sector and furthermore, the willingness of the consumer as well as the market actors to take part in preparing the existing system for a higher EV penetration. According to the project *Grid for Vehicles* [4], the implementation stages are defined as *Conventional Scenario*, *Safe Scenario*, *Proactive Scenario* and *Smart Grid Scenario* with an increasing share of EV in relation to the overall electricity demand in the power system. The market penetration of EV is around 20% in the first two stages and around 40% in the *Proactive* and the *Smart Grid Scenario*.

A short description of these implementation stages with a focus on the main differences is given below. Based on these introductions, policy requirements for the respective integration of EV in each implementation stage are described. Further information on the policy options are given in [5].

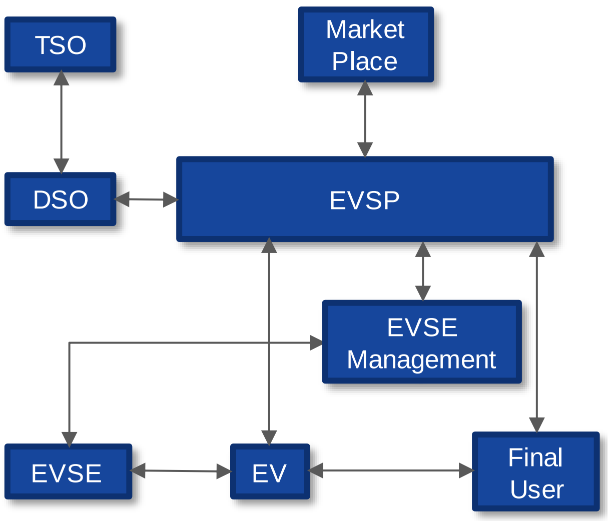



*Figure 4.1 : Overview on different EV services and interactions*

To have a common understanding of different services by EV, a few definitions are given in Figure 4.1 and explained as follows: The electric vehicle supply equipment (EVSE) is represented by a charging station and thus guarantees the access of an EV owner to power outlets. This charging infrastructure has to be provided by the EVSE operator, which in case of public charging might be a station attendant. The electric vehicle service provider (EVSP), as a central instance in the charging process, provides the connectivity of different charging infrastructures across the network of charging stations, which can be represented by private users or an EVSE management including more than one EVSE. They are, for example, connected to central servers or need to be managed using managing software databases and communication interfaces [6].

*Table 4.1 : Overview on the implementation stages given in literature*

| | Conven-tional | Safe | Proactive | Smart grid |
|---|---|---|---|---|
| **EV market penetration** | 20% | 20% | 40% | 40% |
| **Load management** | None | Soft, fleet-focused | Massive | Massive, local |
| **Type of load management** | None | On/off | On/off | Charge modulation |
| **Power system and distribution grid expansion Non EV-related: EV-related:** | Yes<br>Yes | Yes<br>Minimal | Minimal<br>None | None<br>None |
| **Energy flow in EVs that are used to provide services** | None | Grid → EV | Grid → EV | Grid ↔ EV |
| **Authority for load management** | None | EVSE Operator | EVSE Operator/ EVSP | EVSP |
| **Tariffication scheme** | None | Time-of-use | Real-time price | Competitive market |

**Conventional Scenario**

The *Conventional Scenario* has the lowest degree of EV integration into the power system. Hence, there is no load management considered in this stage and no services between EV, EVSE Operator, EVSP and distribution system operator (DSO) are required. This means, the charging of the EV is assumed to be done as early as possible (upon arrival at the charging station) because no incentives for a shift of the charging process are given. The integration of EV, which in this stage is likely to have negative impact on the power system, has to be met by power system and grid reinforcement. As there is no load management given in this scenario, no adaption of existing policies would be necessary.

**Safe Scenario**

In the *Safe Scenario,* the market penetration of EVs remains the same as in the *Conventional Scenario* and the integration of EVs still has to be faced by power system and grid reinforcement. However, the usage of load management, inciting minor changes in charging behaviour of EV owners, should reduce the impact on the power system like the need for peak load power plants as well as grid reinforcement. Load management can be realized using a time-of-use (ToU-) tariff (potentially also applicable to grid access fees) and requires a communication between EVSE operator, fleet operators and DSO. For the *Safe Scenario*, the policies need to enable the establishment of communication infrastructure for following a ToU-tariff.

**Proactive Scenario**
Due to the increasing market penetration of EVs, load management is frequently used in this stage. As there is a higher share of EVs and load management is becoming more complex, next to the EVSE operator, the EVSP has to communicate with the DSO. Thus, no or minimal power system and grid reinforcement is expected in this scenario. For this stage, the policies again need to be more flexible to adapt the charging behaviour to different implementations of load management like charging in times of lowest market prices or the limitation of the highest peak load. Charging in times of lowest market prices requires the implementation of a tariffication scheme to adapt the charging behaviour to real-time prices (RTPs).

**Smart Grid Scenario**
The *Smart Grid Scenario* is the stage with the highest share of EVs integrated in the power system. The main difference coming up in this stage is the bidirectional energy flow between EV and grid, which even helps to better integrate renewable energy sources (RES) capacities without additional need for power system and grid expansion. This bidirectional energy flow enables EVs to feed electricity from the battery back into the grid and is known as vehicle-to-grid (V2G) approach. The communication will be exclusively between EVSP and DSO as there is a competitive market given in this implementation stage instead of contracts for the grid access. Concerning the *Smart Grid Scenario*, policies need to establish a competitive market with the possibility of an active demand for the participation of EV in different markets due to a bidirectional charging.

## 4.2. DETERMINATION OF CHARGING STRATEGIES

Based on the analysis, the charging strategies, which will be assessed via the model-based simulations in this study, are derived from the previously introduced implementation stages. The five distinctive strategies vary in their ability to provide flexibility for the power system as well as in their complexity. The general approach of the strategies is described in the following, whereas the modelling of the strategies is given in Section 5.

**Immediate Charging**
*Immediate charging* means the charging of EVs takes place immediately after arriving either at home in the evening hours or at the office in the morning hours. This strategy is derived from the *Conventional Scenario* in Section 4.1 as there is no incentive to shift charging times. It will be assessed to what extent the increased load may coincide with existing peaks especially in the evening hours. This possible coincidence could result in a shift in generation dispatch or the amount of grid reinforcements and is therefore assessed in this study.

**ToU-Based Charging**
In compliance with the Safe Scenario from Section 4.1, the *ToU-based charging* strategy considers fixed price signals (such as a ToU-tariff) to change the customer charging behaviour and thus facilitate EV integration into the power system and grid. To optimize the customer requirements, grid management and the electricity generation, price signals as well as control signals are necessary. For the *ToU-based charging* approach, only a unidirectional communication is required, from the power system towards the EV.

**RTP-based Charging**

*RTP-based charging*, which is associated with the Proactive Scenario, aims at the integration of RES and the avoidance of power system and grid reinforcements by charging in periods of high generation from RES and therefore a smoothened residual load[9]. The optimization can be based on a price signal, e.g. the hourly market price being reflected via an hourly real-time price for EVs.

**Vehicle to Grid**

Furthermore, a V2G-approach as defined in the Smart Grid Scenario of Section 4.1 is conceivable. Next to the unidirectional charging of EV in the previous scenarios, this approach allows the discharge of EV as infeed into the grid. For the implementation of this approach, a bidirectional communication is necessary.

[9] Residual load is the remaining electricity demand when subtracting the generation from RES.

# 5. MODELLING OF CHARGING STRATEGIES

For the model-based assessment in this study, the different charging strategies, derived from the literature-based analysis in Section 4, need to be integrated into the simulation of the power system. The following sections will outline how these charging strategies are implemented and simulated in the METIS model. Before describing the different charging strategies, the input data and appropriate assumptions are introduced. Furthermore, the base scenario is introduced, as it is used for modelling in some parts.

## 5.1. INPUT DATA FOR EV MODELLING

For the model-based assessment of the different charging strategies with the METIS tool, the input data and the major assumptions are described in the following.

The input data is based on three different scenarios developed by the ICCS-E3M-Lab with the PRIMES model. These projections include the annual electricity demand by electric vehicles and the vehicle stock for all EU Member States for two distinct vehicle types (BEV and PHEV) for the scenarios EUCO30 in 2030, EUCO30 in 2050 and REF16 in 2030[10] [7]. The REF16 and EUCO30 scenarios differ in terms of renewables share in the power system (REF16 in 2030: 42.6%, EUCO30: 49.5% in 2030 and 64.4% in 2050) and the share of electricity in passenger cars energy demand (< 5% in 2030 for REF2016 and EUCO30, 34% in 2050). Taking into account that the REF16 and EUCO30 scenarios only provide projections for the 28 EU countries, the determination of the input data for the remaining six countries strongly interlinked with the EU power system[11] is based on the input data of the neighbouring countries: the EV demand and EV stock are averaged and afterwards scaled by population.

The differentiation between weekday and weekend day and the charging capacity is given independently of each country. Furthermore, the time shift of each country by the meaning of their everyday working times for immediate charging and the marginal cost by country and hour based on a preliminary reference simulation are given. Based on this, the input data for the modelling is derived in the same way for all scenarios as given for EUCO30 in 2030 in the following. For the determination of the daily demand by Battery Electric Vehicle (BEV) and Plug-in-Hybrid Electric Vehicle (PHEV), it is assumed that only 70% of the total amount of EV participate in travel [8]. It was further assumed that half of the participating vehicles charges at home while the other half charges at work (cf. Figure 5.1).

[10] The EU Reference Scenario 2016 (REF16) provides developments under current trends and adopted policies. It assumes that the climate and energy legally binding targets for 2020 will be achieved and that the policies agreed at EU and Member State level until December 2014 will be implemented. Building on the EU Reference scenario 2016, the ‘EUCO30’ scenario has been developed to reach all the 2030 targets agreed by the October 2014 European Council (at least 40% reduction in greenhouse gas emissions with respect to 1990, 27% share of RES in final energy consumption and 30% reduction in the primary energy consumption) and the 2050 decarbonisation objectives, continuing and intensifying the current policy mix.

[11] EU28 + Norway, Switzerland, Bosnia and Herzegovina, Serbia, FYROM, Montenegro.

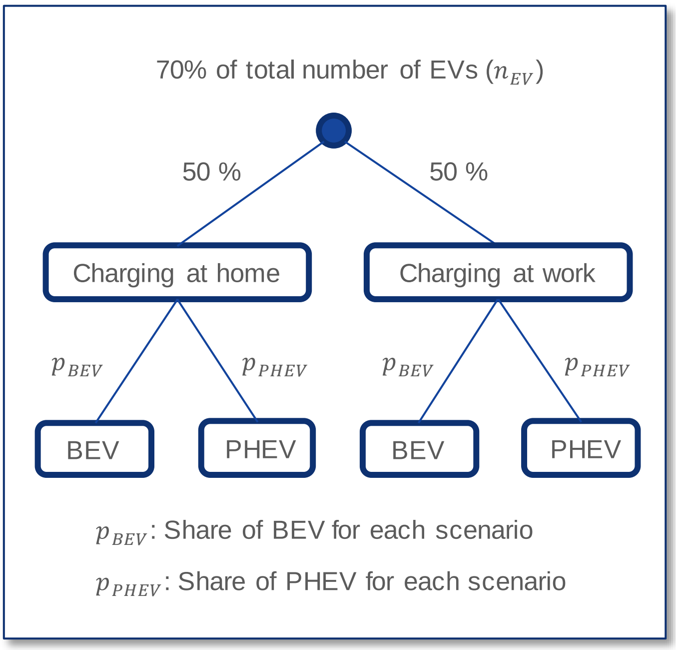



*Figure 5.1: Assumptions for the participation at each charging location by type*

The allocation of BEV and PHEV depends on the share of each vehicle type in the corresponding scenario. Considering a charging capacity of 3.3 kW[12] and the daily demand at weekdays to be three times higher than the daily demand at weekend days [8], the daily demand ranges between 5.5 and 15.6 kWh/d for BEVs and between 2.1 and 14 kWh/d for PHEVs in the EUCO30 in 2030 scenario (cf. Figure 5.2).

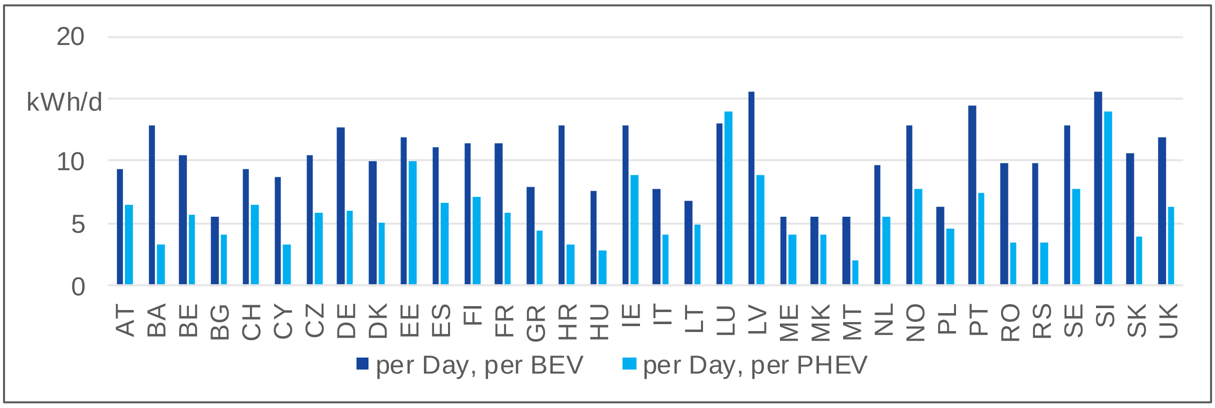



*Figure 5.2: Daily demand at weekdays for BEV and PHEV in EUCO30 in 2030 scenario*

For the given annual electricity demand (based on the scenario data) and the charging capacity of 3.3 kW, the daily charging duration (given in Figure 5.3) ranges between two and five hours for BEVs and between one and five hours for PHEVs.

[12] The assumed charging capacity of 3.3 kW is rather conservative, as a 3-phase-system is already available to provide above 10 kW. Fast charging stations, providing more than 100 kW of charging capacity, are already under discussion [9].

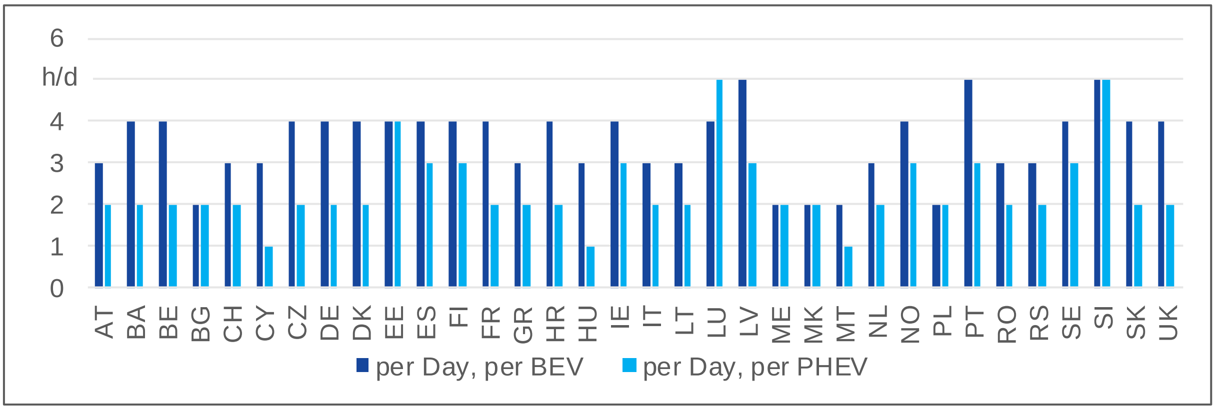



*Figure 5.3: Daily charging hours for BEV and PHEV in EUCO30 in 2030 scenario*

Based on these daily charging durations, the generation of hourly charging profiles is performed. In the following, the related modelling of the charging strategies and the required input data are introduced.

## 5.2. BASE SCENARIO

Initially, the modelling of the REF16 and EUCO30 scenarios was undertaken in METIS without an explicit representation of EV demand and optimization. Instead, the national load curves from ENTSO-E's TYNDP 2014 were scaled according to the annual electricity demand given for the REF16 and EUCO30 scenarios [10]. This means that EV-related electricity demand followed the same hourly distribution as overall demand profile, without a distinct representation of a specific EV charging pattern.

## 5.3. IMMEDIATE CHARGING

The immediate charging, as described in the literature review, represents charging of BEVs and PHEVs upon arrival at home or at work. The approach for the immediate charging is to set the start of the charging process at the arrival time of each EV. The charging duration then equals the charging hours, which is derived from the daily demand per EV (cf. Figure 5.2). The result of the method is in an hourly resolved charging profile for each country depending on the annual demand, the number of EVs, the share of BEVs and PHEVs as well as the arrival times at work and at home. While the information on annual demand and EV numbers is based upon PRIMES projections the arrival times (cf. Figure 5.4, left) are based upon a study from the French General Commission for Sustainable Development [8]. The resulting charging profile for one weekday in Germany for each EV type is given in Figure 5.4 on the rights side.

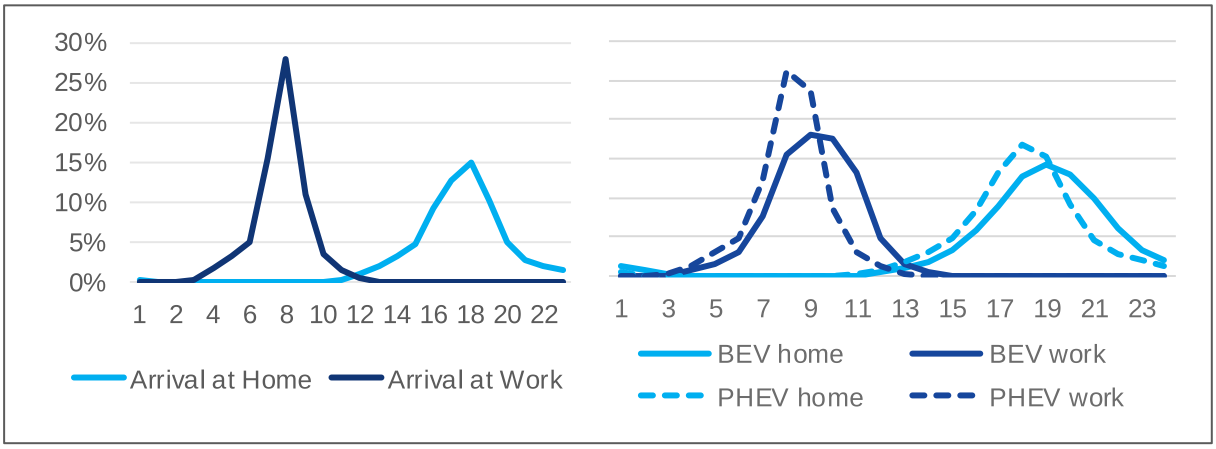



*Figure 5.4: Daily arrival times at home and at work for countries without time shift (l) and corresponding charging profile of Germany as example (r)*

As driving patterns differ across the European countries, the determined charging profiles are shifted according to their daily activity [11]. This results in a shifted participation in travel that is modelled by a shift of charging profiles. Based on information from a time use survey [11], countries were clustered in two groups, one including all countries with similar activity patterns than in France and one with countries featuring activity patterns being shifted by one hour forward compared to the French reference[13], cf. Table 5.1.

*Table 5.1: Time shift of each country*

| No time shift | Time shift of minus one hour |
|---|---|
| **Belgium, Switzerland, Cyprus, Denmark, Estonia, Spain, France, Greece, Ireland, Italy, Latvia, Malta, Norway, Portugal, United Kingdom** | Austria, Bosnia and Herzegovina, Bulgaria, Germany, Czech Republic, Finland, Croatia, Hungary, Lithuania, Luxembourg, Montenegro, Republic of Macedonia, Netherlands, Poland, Romania, Serbia, Sweden, Slovakia, Slovenia |

For countries with similar daily activities as France, the charging profile remains the same as the one generated from the data given in Figure 5.4. For other countries with a start of activities approximately one hour ahead (e.g. Germany), the generated charging profile is shifted forward by one hour.

## 5.4. ToU-Based Charging

ToU-based charging is defined by the preferred charging during prior specified, static low price periods given by so-called time-of-use-tariffs (ToU). In this study, ToU-periods are determined based on the hourly marginal electricity costs in the base scenario for each country. The base scenario is a scenario without any adaption of EV charging. For the determination of the ToU-periods, seasonal as well as weekly effects are considered by the differentiation of summer and winter as well as weekday and weekend day. First, the mean value for every hour of a day for e.g. a weekday in summer is determined. Using the 50%-quantile, twelve hours of the days are classified as low price and the remaining twelve hours as high price periods. The resulting mean values for the marginal costs and the 50%-

[13] Independent from this correction, the METIS model takes into account the different time zones.

quantile of France and Germany are given in Figure 5.5, for the EUCO30 in 2030 scenario as example.

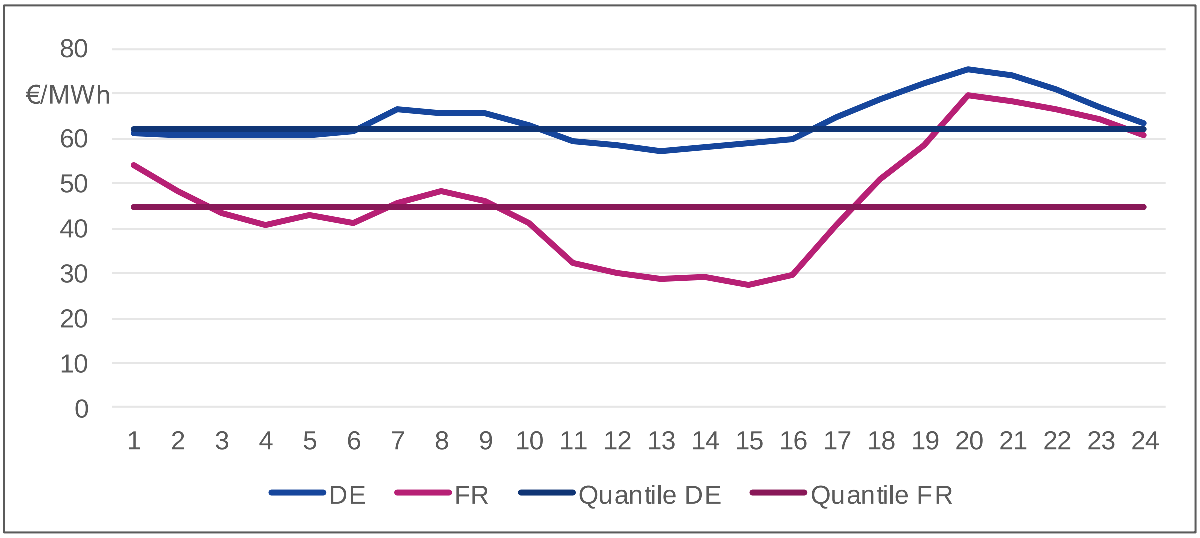
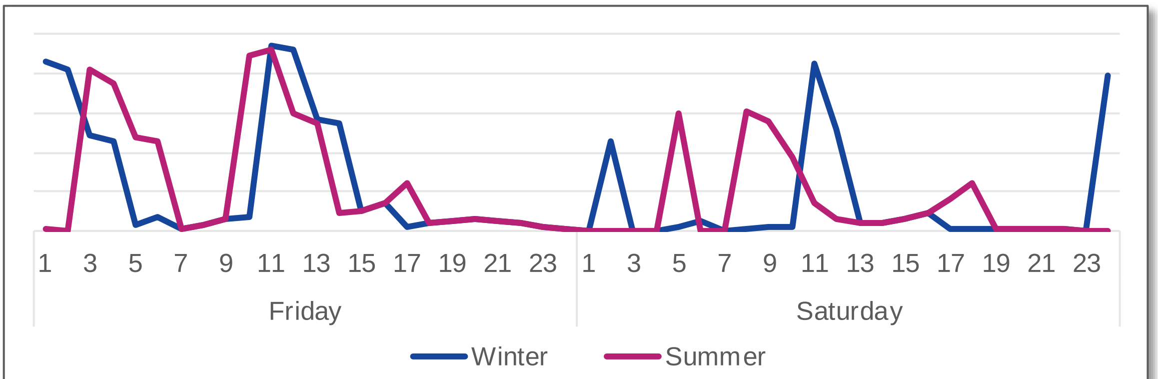



*Figure 5.5: Mean values of one day for marginal cost in EUCO30 in 2030 scenario*

Assuming that it is more desirable to charge EVs as early as possible and in a situation, where the arrival time coincidences with a low price period, the EV is charged until the daily charging hours are reached or a high price period begins. If the arrival time coincidences with a high price period, the charging begins in the next low price period. In Figure 5.6, the derivation of the charging profiles from the ToU-tariffs is illustrated for France as example. An illustration of ToU-based charging patterns across all countries is provided in the Annex, Section 9.2.2




| hours | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sum, wd | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| sum, we | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 |
| win, wd | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| win, we | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 |

0 Low price period    1 High price period

*Figure 5.6: Charging profile France for winter and summer in EUCO30 in 2030 scenario*

Considering the case, that between the arrival and the departure of the EV, the charging hours exceed the hours of low prices, the EV necessarily has to be charged in high price periods as well.

Based on the share of each charging strategy, the charging profiles of BEV and PHEV at home as well as at work are aggregated. They serve as exogenous input for the METIS simulation framework. The result of this data processing is an annual charging profile for each country in hourly resolution.

### 5.5. RTP-BASED CHARGING

The RTP-based charging reflects the case of adapting the charging behaviour to RTP, which means EVs obtain a price signal that varies hour by hour. In contrast to immediate and ToU-based charging, the charging profile of RTP-based charging is determined endogenously in the model. Next to the input data described in Section 5.1, it must be ensured that EV have to charge between their arrival and departure time, which adds a restriction to the optimization. The number of EVs that are currently connected to the grid depends on the hourly arrival and departure time series.

Under the given modelling setup, the main objective of the optimisation (which is formulated as overall system cost minimisation) is to ensure that charging takes place in hours of lowest market prices. As market prices correlate with the residual load, charging is expected to be shifted in times of low residual load, while reducing residual load peaks. As this is a market-based optimization, it may lead to additional system stress for the distribution as well as the transmission grid. Although, RTP-based charging could also take into account grid related constraints, this is out of scope of the study, since it would require a detailed modelling of the distribution as well as the transmission grid. Yet a simplified analysis of grid-compliant charging is carried out, limiting the number of EVs charging simultaneously to a pre-defined maximum value.

Considering these restrictions, the charging behaviour is determined by a joint optimization of EV charging and the dispatch of power generation assets. For the hourly optimization of the charging profiles, it is reckoned that each vehicle must be totally charged before departure. In addition to that it is assumed that during its journey each vehicle is discharged from a constant level of energy, which is given by the daily demand per EV. If an hour with equivalent market conditions occurs, the charging takes place as early as possible to reflect consumers' preferences.

### 5.6. VEHICLE TO GRID

The V2G approach, as described in Section 4.2, is based on the RTP scenario. Assumptions and restrictions from the RTP scenario have to be considered in this approach as well. Especially, with the ability to discharge the grid, it is important that each vehicle has to be totally charged prior to departure from terminal. Apart from that, the discharging is only limited by the discharging capacity, which is similar to the charging capacity considering efficiency losses of 20%, and a maximum discharge of the battery equal to the mean daily demand[14] [12].

[14] The impact of a frequent discharging on the performance and the lifetime of the battery using the V2G approach and therefore a lower acceptance of EV owners to participate in V2G schemes, might be a limiting factor for V2G uptake, but with decreasing importance in time. In the study, this effect is not considered, as the focus is on the impact of different charging behaviour on the electricity system.

# 6. SCENARIO ASSESSMENTS

To determine the impact of electromobility on the power system, analyses of the different charging strategies from Section 5 are carried out under a varying set of assumptions, e.g. regarding the power system, the share of EVs and RES in final energy demand or the $CO_2$ price. In the first part of this section, the different scenarios will be introduced. Based on this, the results for the defined scenarios are given in the second part.

## 6.1. Scenario Definitions

A scenario, as defined in this section, is the combination of one REF16/EUCO30 scenario with a specific charging strategy. The REF16/EUCO30 scenarios are given on the left side of Figure 6.1 and describe for example the annual electricity demand of EVs, the number of EVs, the $CO_2$ prices and the capacity mix of the power system including a specific RES share (cf. Section 5.1).

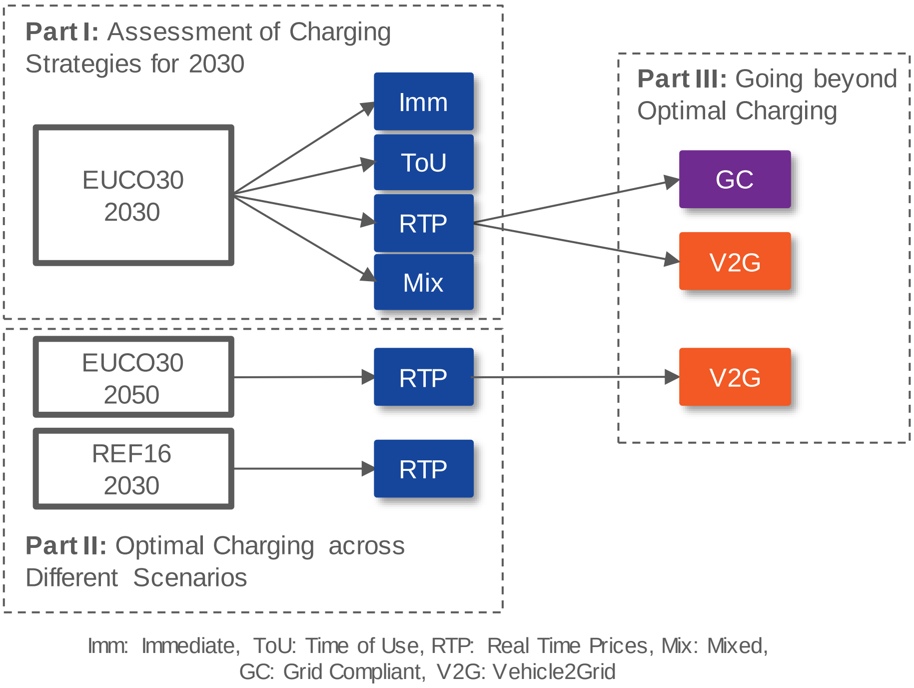



*Figure 6.1 : Overview on dimensions to be investigated*

For these scenarios, annual simulations are conducted in an hourly and countrywide resolution. The simulation without any adaption of EV charging is referred to as the base scenario[15]. Based on the derived charging strategies, different charging scenarios are developed:

- Immediate scenario (Imm): 100% Immediate charging
- ToU scenario (ToU): 10% Immediate, 90% ToU-based charging
- Mixed scenario (Mixed): 50% Immediate, 40% ToU, 10% RTP-based charging

[15] Base scenario: Integration of EV demand in national load curves from ENTSO-E TYNDP without a distinct representation of the charging pattern (c.f. Section 5.2).

- RTP Scenario (RTP): 10% Immediate, 90% RTP-based charging
- Vehicle to Grid (V2G): Based on RTP scenario with ability to feed electricity to the grid
- Grid compliant (GC): Based on RTP scenario with capped capacity for charging simultaneously

Part I focuses on the impact of different charging scenarios on the power system. Therefore, as illustrated in Figure 6.1, the first four charging scenarios are assessed for the same REF16/EUCO30 scenario, which is EUCO30 in 2030. In the second part, the assessment focuses on the changes in the REF16/EUCO30 scenario. The charging scenario remains the same (RTP-based charging), but the REF16/EUCO30 scenarios EUCO30 in 2030, EUCO30 in 2050 and REF16 in 2030 are assessed. In the last part, the impact of V2G as well as the grid compliant charging scenario are assessed, both considering restrictions as well as assumptions from the RTP scenario.

## 6.2. RESULTS[16]

### 6.2.1. *PART I – ASSESSMENT OF CHARGING STRATEGIES FOR 2030*

**Charging profiles**

Figure 6.2 to Figure 6.5 show the charging profiles for two 3-day excerpts (Fr/Sa/Su) in winter as well as summer season for the assessed charging scenarios. The grey line is the residual load and indicates times of low and high residual loads. The difference between the residual load curve in winter and summer season results from PV infeed, which shows higher levels and gradients in summer. Figure 6.2 as well as Figure 6.3 show that charging peaks of the immediate scenario coincide with residual load peaks especially in the evening hours. The ToU scenario instead, prevents charging in the evening hours and leads to a shift into subsequent night time hours. The best alignment with the residual load is reached under the RTP scenario, which can be observed by having charging peaks in the morning hours and hours of the early evening in winter season (cf. Figure 6.5). For the mixed scenario, charging in hours of low residual load occurs, but charging in evening hours with higher residual load than in midday hours in the winter season occurs as well. The resulting charging profiles reflect the different share of each charging strategy. Due to the high share of the immediate charging behaviour in the immediate (100%) and the mixed scenario (50%), peaks in charging profiles coincide with peaks in residual load. Based on the analysis of the resulting charging profiles, the impact on the power system is described in the following.

[16] All results in this chapter are given for EU28 countries, figures for EU28+6 countries are given in Annex 9.3.1.

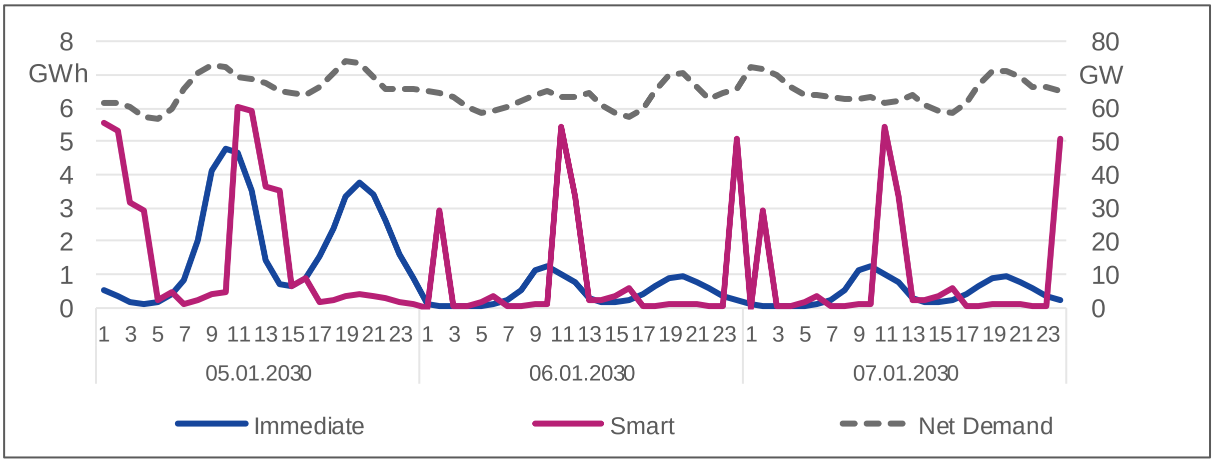



*Figure 6.2: Charging Profile of Immediate and ToU Scenario, France in summer*

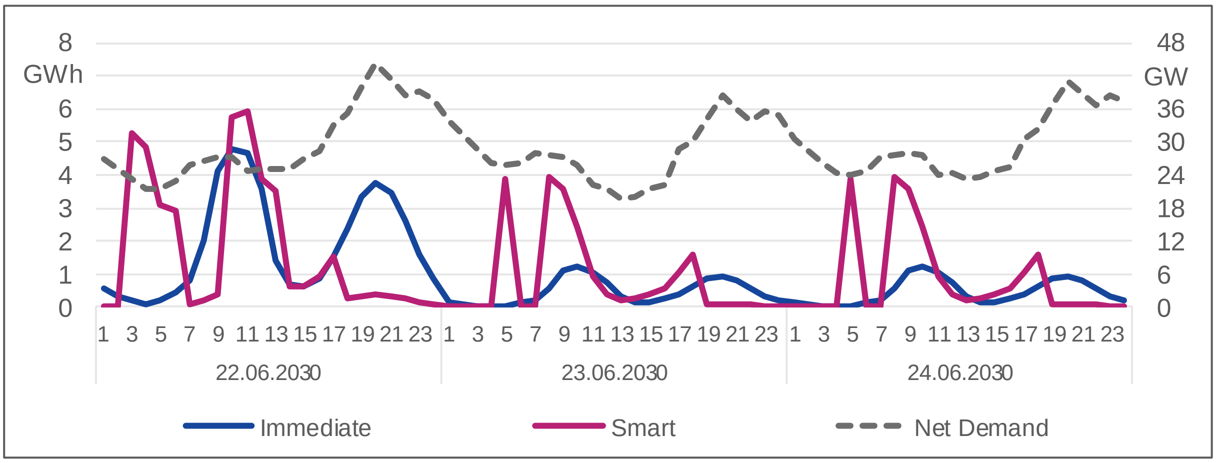



*Figure 6.3: Charging Profile of Immediate and ToU Scenario, France in winter*

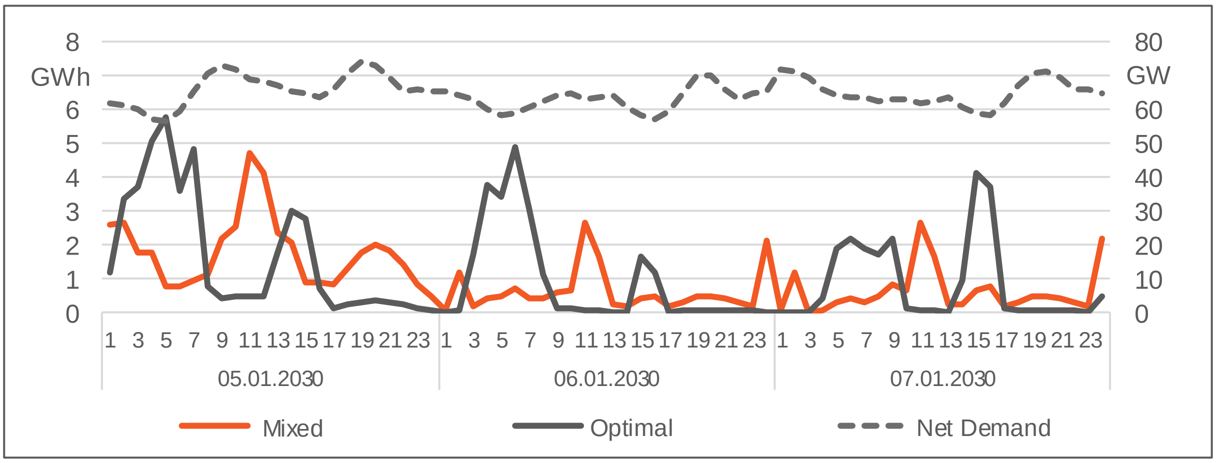



*Figure 6.4: Charging Profile of Mixed and RTP Scenario, France in summer*

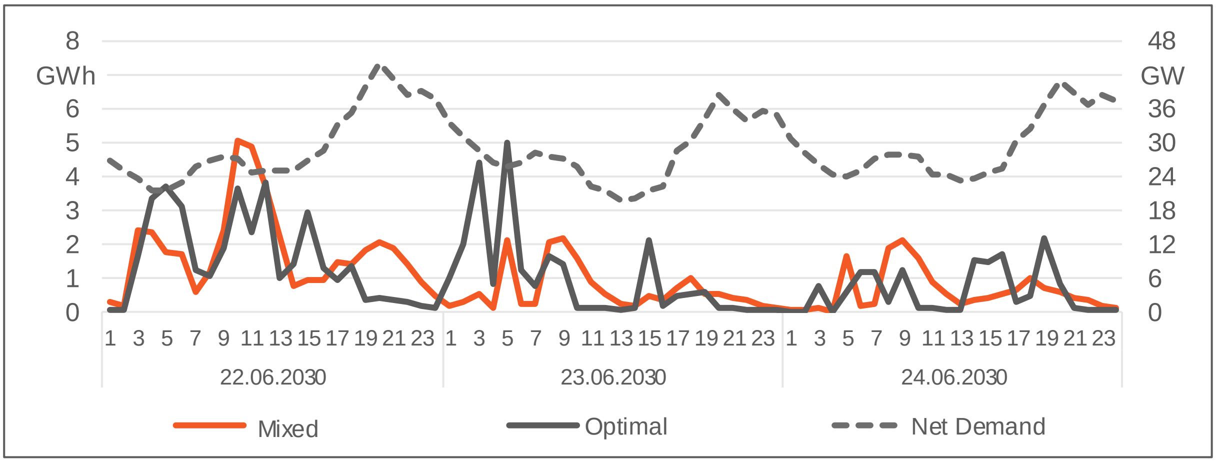



*Figure 6.5 : Charging Profile of Mixed and RTP Scenario, France in winter*

**Overall system load curve**

Figure 6.6 gives an example of changes of the overall system load in France for three winter days (same days as given for the charging profiles in Figure 6.2 to Figure 6.5). The graph for the net scenario shows the load curve excluding EV demand. In the immediate scenario, the evening peak load is enhanced, for example for France by 4 GW or 3.7%. The load curve of the ToU scenario shows that charging partially is shifted to hours of low load such as in the early hours of Saturday, but due to the assumption that 10% of EV owner are charging following the immediate charging profile, enhanced peaks in evening hours occur as well. Charging in the RTP scenario avoids charging in the evening hours. Thereby, additional local peaks in midday can be explained by low residual load in this hours due to relatively high PV infeed especially in France.

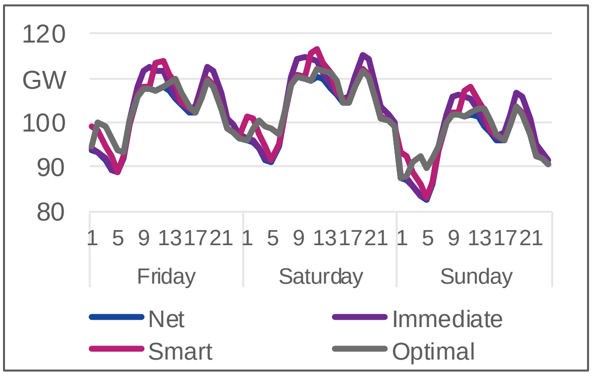



*Figure 6.6 : System load curve France, January*

**Expected Energy not Served**

The Expected Energy not Served (EENS) is the annual energy demand (measured in GWh/a) that is expected not to be met by generation (also referred to as loss of load). Figure 6.7 shows the simulated EENS for selected countries featuring a significant EENS as well as significant differences between the charging scenarios. The highest EENS in all countries results for the immediate scenario because of the coincidence between demand peaks and peak of the charging profile. For example, in Germany, the EENS in the immediate scenario equals 71 GWh or a share of 1-2% in total electricity demand, this means at the same time around 17 hours with loss of load per year. In the ToU scenario, the EENS can be reduced by over 50% compared to immediate charging. In Germany, with a reduction of EENS of nearly 80% compared the immediate scenario, the most significant changes can be observed. Charging in the RTP scenario leads to the lowest EENS. As well as for the alignment of the residual load, the share of each charging strategy is the most determining parameter for the EENS.

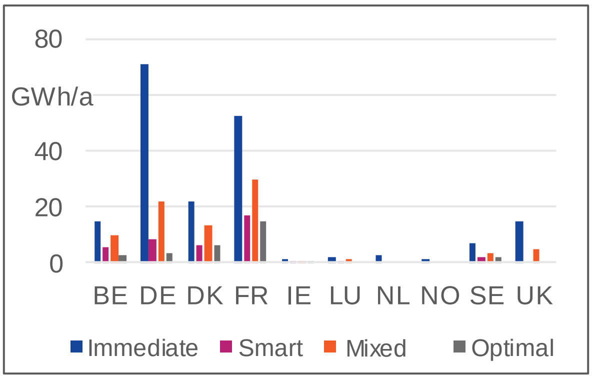



*Figure 6.7: Expected Energy not Served*

**Difference in generation**

Figure 6.8 shows the summarized difference in generation dispatch for all assessed countries between the RTP and the immediate scenario. The technologies with negligible differences in generation dispatch are not depicted. Due to the shift of demand to hours with lower residual load in the RTP scenario, the dispatch of flexible generation units like gas turbines or pumped storages is reduced. This difference in generation is associated with a higher utilisation of base load power plants like nuclear, coal and lignite. Nevertheless, the difference in generation dispatch has no significant impact on $CO_2$ emissions.

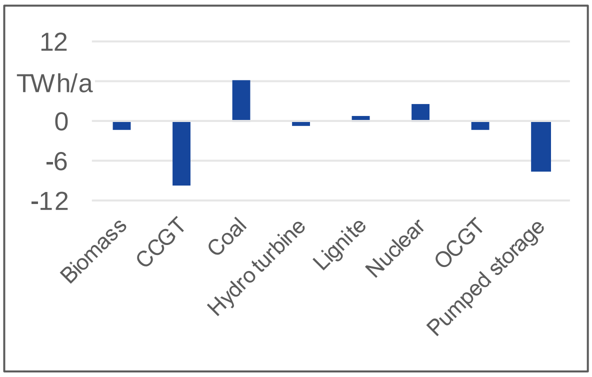



*Figure 6.8 : Difference in generation between RTP- and immediate scenario (EU28 countries)*

In Figure 6.9, the mean marginal costs for each country in the immediate scenario are given. At the right side of this figure, the difference in marginal costs between the RTP- and the immediate scenario is given. The change of charging behaviour and the related difference in generation result in a reduction of mean marginal costs across all EU28 countries for the ToU-based charging scenario by 13.0% (EU28+6: 14.1%) and the RTP-based charging scenario by 22.1% (EU28+6: 26.8%) compared to the immediate charging scenario. This effect can be explained by the fact that ToU- and RTP-based charging substantially reduce the EENS which is penalised with a related cost of 15000 €/MWh. Especially in the middle and northern parts of Europe marginal costs are hence reduced significantly. The integration of EVs in a smart or rather optimal manner gives the chance to reduce power system costs.[17]

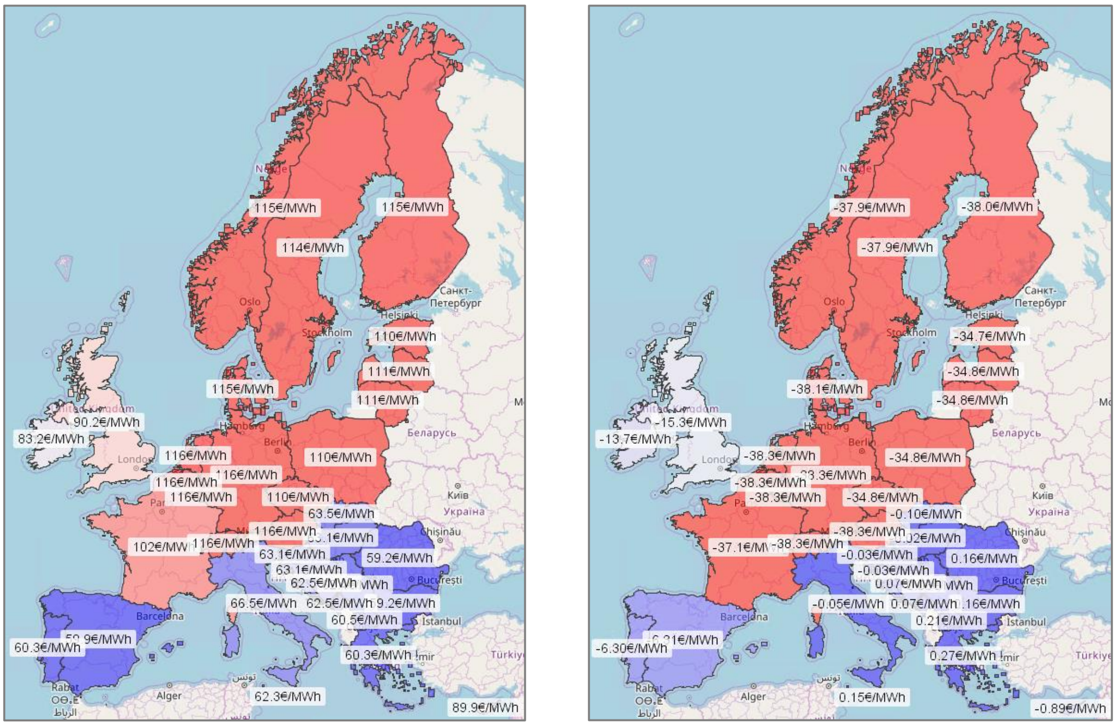



*Figure 6.9 : Marginal costs for immediate scenario (l) and difference of RTP- and immediate charging (r) in EUCO30 in 2030 REF16/EUCO30 scenario*

**Residual load**

The last indicator to assess the impact of the different charging scenarios on the power system is the residual load. In Figure 6.10 the mean residual load of the different charging scenarios across all summer weekdays is given. In general, the residual load is relatively low in midday hours due to high infeed from photovoltaic and relatively high in the evening hours due to a major part of consumers being at home and at the same time low infeed from photovoltaic. Considering the assessed scenarios, the immediate scenario exhibits the highest gradients due to the coincidence of evening charging and simultaneous load peaks. In all scenarios containing ToU- and RTP-based charging, the residual load maxima as well as minima can be smoothened, but the RTP scenario levels the residual load with highest impact.

[17] Slightly higher marginal costs in some countries may result from different import and export for the given scenarios. As example in Malta, the net import decreases, which results in the given increase of marginal costs.

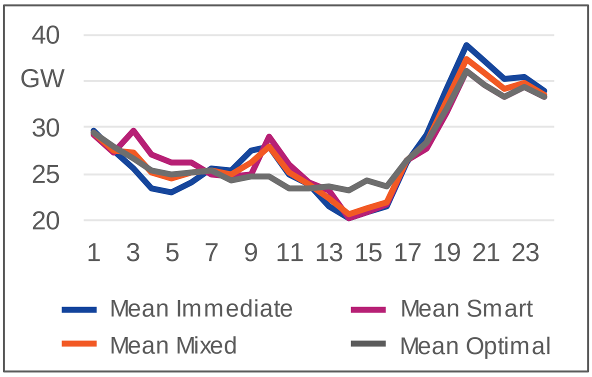



*Figure 6.10 : Mean residual load of weekdays in summer (France)*

Summarizing the different indicators for the impact of EV charging behaviours on the power system, it can be noted that the RTP-based charging scenario has the highest impact and therefore, can be considered as the most promising strategy for an effective integration of EV into the power system. For this reason, the following analyses are focussed on the RTP scenario.

**Summary**

Immediate charging creates load peaks in 2030 due to the charging in hours of high residual load (in particular in early evening hours), implying risks of loss of load if no sufficient generation capacity is made available. Going from immediate to time-of-use-based charging, the risk of expected energy not served is reduced significantly as the incentive to charge in low price periods via the time-of-use-tariff mainly avoids additional load peaks resulting from EV charging. This means in detail that the time-of-use-tariff, which is applied in the time-of-use charging scenario allows to avoid a further increase of the evening peak in residual load. Thus, the utilisation of expensive peak load capacities can be limited, which results in lower marginal costs (- 13%) compared to the immediate scenario. Therefore, the negative effects are mitigated, but the real-time price-based charging provides an additional value in terms of 22% reduction in mean marginal generation costs, which is realised by a further decrease of expensive peak load capacities and the enhanced utilisation of base load capacities. Furthermore, the production costs[18] can be reduced by 728.1 Mio. € (- 1.1%) for real-time price-based charging compared to uncoordinated (immediate) charging. Next to the cost reduction concerning the overall power system, there are savings given for the EV owner as well, which highly vary between the investigated countries. [19] For example, in Italy, the savings for EV owners equal some 13% for the RTP-based charging compared to immediate charging. The impact of RTP on the system-wide $CO_2$ emissions is negligible. As it is not likely that all electric vehicle owners will adapt their charging behaviour to real-time-prices, the mixed scenario shares benefits from real-time price- and time-of-use-based charging. Thus, negative effects on the power system due to uncoordinated charging can be avoided. As an example, the expected energy not served is reduced significantly due to real-time price-based charging (e.g. DE -70% and FR -40%).
In conclusion, the results indicate that in the long run the question is not if electric vehicles need to be integrated in a smart manner (as the immediate charging scenario reveals

[18] Production costs do not include battery costs as well as costs for installation of new generation capacities but are limited to costs related to fuel purchase and $CO_2$ emission allowances.

[19] Cost savings depend on two factors, (1) the changes in the load profile leading to EV charging in times of lower costs as well as (2) the overall reduction in power prices due to adapted EV charging.

substantial costs and risks related to expected energy not served), but rather which is the best way to integrate them in a cost-efficient and system-friendly way.

### 6.2.2. ***Part II – RTP-based charging across different scenarios***

In this part the focus is set on the RTP scenario under consideration of different REF16/EUCO30 scenarios, featuring different degrees of EV and RES penetration. The RTP-charging scenario is analysed for the REF16/EUCO30 scenarios. For a better understanding of the results from this assessment, the REF16/EUCO30 scenarios are first presented, followed by the presentation of the results.

**REF16/EUCO30 Scenarios**

The main results of the different REF16/EUCO30 scenarios before optimization of EV charging for EU28 countries are given in Table 6.1.[20] Overall electricity demand for EU28 countries in REF16 in 2030 scenario amounts up to 3083 TWh, including 25 TWh of EV-related electricity demand, whereas in the EUCO30 in 2030 scenario EVs increase electricity demand by 61 TWh to 2975 TWh in total. The EV integration in the REF16 in 2030 scenario is the most conservative one and results in a share of electricity of about 1% in the passenger car electricity demand. In EUCO30 in 2050 the higher penetration of EVs is given by an additional electricity demand of 365 TWh (10%); the share of electricity in passenger car road transport sector is around 34%.

*Table 6.1: Main data of REF16/EUCO30 Scenarios ($CO_2$ emissions prior to EV charging optimisation) for EU28 countries*

| | Additional electricity demand by EV | Share of electricity in passenger cars energy demand | Number EV in EU28+6 countries [M.] | $CO_2$ emissions in power generation sector [Mt] | RES share in overall production [%] |
|---|---|---|---|---|---|
| REF16 2030 | 25 TWh 0.8% | 1.4% | 15 | 677 | 42.6 |
| EUCO30 2030 | 61 TWh 2.1% | 3.9% | 36 | 627 | 49.5 |
| EUCO30 2050 | 356 TWh 10.4% | 34.3% | 190 | 203 | 64.4 |

$CO_2$ emissions as well as the shares of RES production given in Table 6.1 are derived from the annual utilisation of power generation capacities of the base scenario, without any adaptation of EV charging. The emission reduction between 2030 and 2050 results from the increasing $CO_2$ price[21] that is projected in EUCO30 scenario. For example, as shown in Table 6.2, this effect can be explained by the merit order of the EUCO30 scenarios for Germany. In 2030, marginal generation costs are the lowest for coal power plants followed by gas turbines and finally biomass, whereas in 2050 biomass has the lowest marginal costs followed by gas turbines and coal power plants[22]. This effect is commonly known as fuel switch. Due to lower cost for the usage of biomass power plants and gas turbines

[20] Data for EU28+6 countries is given in Annex 9.3

[21] $CO_2$ price in 2050 above 100 €/t

[22] Due to nuclear phase-out in Germany in 2022, no nuclear power plants are dispatched in this scenario.

instead of coal power plants, the $CO_2$ emissions in the EUCO30 in 2050 scenario are reduced significantly, as described before.

*Table 6.2: Merit order of different power plant technologies in Germany*

| | 2030 | 2050 |
|---|---|---|
| 1 | Lignite | Biomass |
| 2 | Hard Coal | CCGT |
| 3 | CCGT | OCGT |
| 4 | OCGT | Hard Coal |
| 5 | Biomass | Lignite |

**Results**

To point out the impact of the RTP-based charging in each REF16/EUCO30 scenario, it is compared to the base scenario of the respective REF16/EUCO30 scenario. As already mentioned, the base scenario is a scenario without a distinct representation of the charging pattern.

In Figure 6.11 the impact of the RTP-based charging on the **power plant dispatch** is given by the difference of the production between the RTP- and the base scenario for REF16/EUCO30 scenarios as a sum of all EU28 countries. At first it can be seen that the impact of the implementation of RTP-based charging correlates with the share of EV demand. Especially in 2050, an important potential of flexibility for the power system is given by the EV fleet.

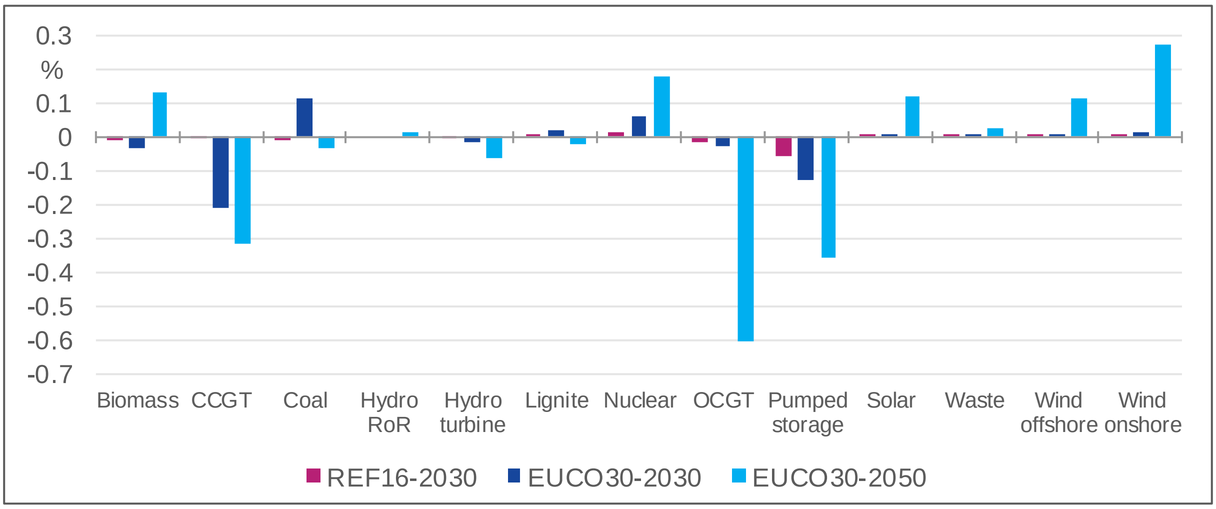



*Figure 6.11: Difference in generation between RTP- and base scenario for all REF16/EUCO30 scenarios as a sum of EU28 countries*

Like in Part I, the implementation of RTP-based charging in the EUCO30 in 2030 scenario reduces the dispatch of flexible power plants, especially the dispatch of gas turbines, whereas the usage of base load power plants like coal and nuclear power plants increases. The impact of the RTP charging in the REF16 in 2030 scenario is analogue to the EUCO30 in 2030 scenario, but with a decreased dispatch from hard coal power plants and a lower increase of the usage of lignite power plants due to the slightly higher $CO_2$ price in the

REF16 scenario. In the EUCO30 in 2050 scenario, there is a significantly lower usage of flexible power plants which results in a shift to base load power plants with low or without $CO_2$ emissions like biomass or nuclear power plants. The usage of coal power plants decreases. More details on the generation mix for the different REF16/EUCO30 scenarios are given in Annex 9.3.

In 2030, there is no significant change in **$CO_2$ emissions**, whereas in 2050 the $CO_2$ emissions can be reduced by 7.9% in sum for EU28 countries (EU28+6: 8.2%) due to the implementation of RTP-based charging. Figure 6.12 shows this reduction in a country-wide resolution in absolute and relative values. It can be seen that in absolute terms, emissions are most significantly reduced in countries like Spain, Germany, France, whereas relative reductions are most important in South-Eastern European countries. The higher impact in 2050 results from the increase of the $CO_2$ price from 2030 to 2050 and a higher potential of flexibility from EV.

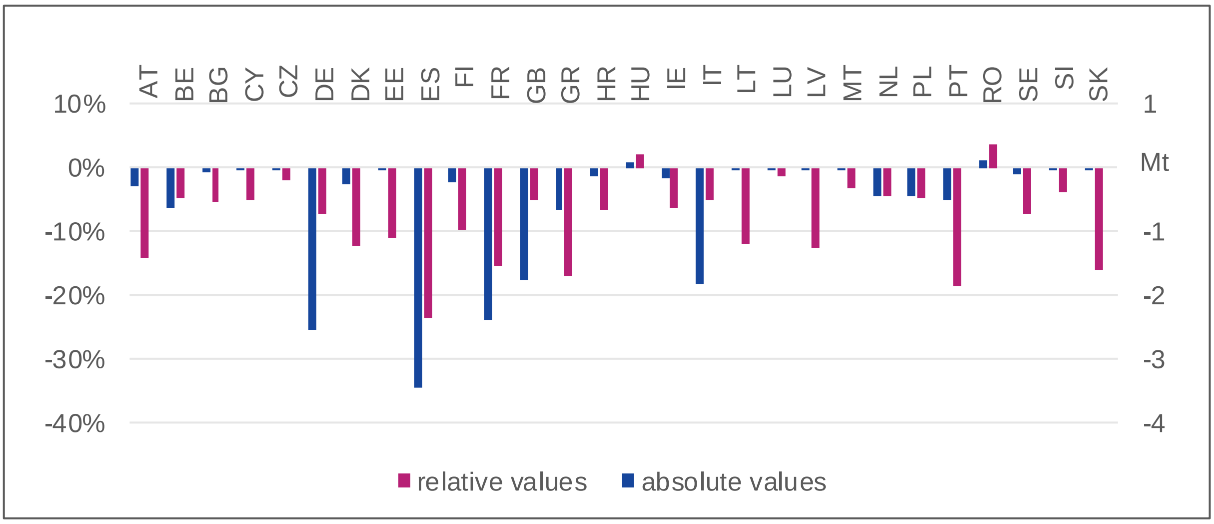



*Figure 6.12 : Relative change in $CO_2$ emissions between RTP and base scenario in EUCO30 in 2050 for EU28 countries*

Furthermore, the difference of the infeed from onshore, offshore and solar power plants can be explained by a lower amount of curtailment (e.g. -23% in 2050 for EU28 as well as EU28+6 countries) due to enhanced utilisation of RES surplus for EV charging. The **curtailment** in the different REF16/EUCO30 scenarios, for the base and the RTP-based charging scenario can be seen in Figure 6.13.

The absolute curtailment in 2050 is significantly higher than the curtailment in the scenarios for 2030, whereas at the same time the highest percentage decrease of curtailment due to the implementation of RTP-based charging is given in 2050. The percentage decrease highly depends on the flexibility potential from the EV fleet.

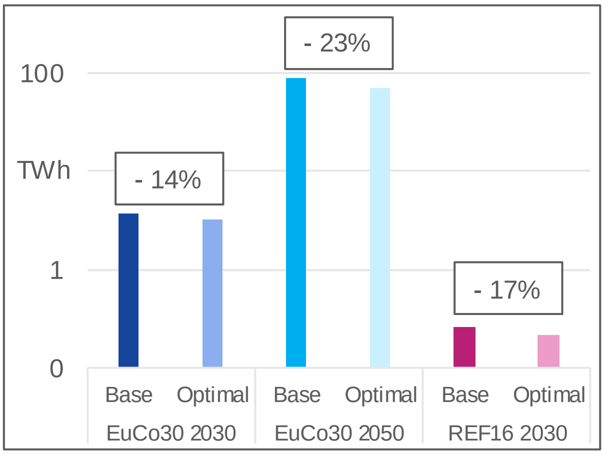



*Figure 6.13 : Curtailment in different REF16/EUCO30 scenarios due to RTP-based charging for EU28 countries*

In Figure 6.14 the Expected Energy not Served, **EENS,** is given for all REF16/EUCO30 scenarios as a comparison of the RTP- and the base charging scenario. The different bars show the sum of EENS in all EU28+6 countries.

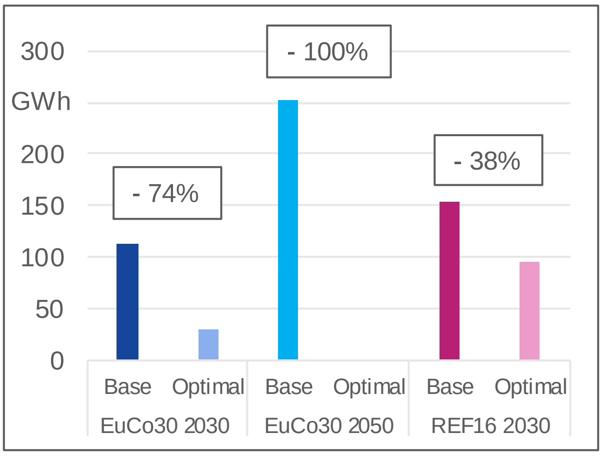



*Figure 6.14 : Difference of Expected Energy not Served in all REF16/EUCO30 scenarios for EU28 countries*

The base scenario of 2050 has the highest value of EENS (1-2% of annual electricity demand), whereas at the same time the implementation of RTP-based charging results in a total removal of EENS for this charging scenario[23]. In contrast to that, a higher demand from EV means a higher potential flexibility for the power system, therefore, the relative reduction is the lowest for the REF16 in 2030 scenario with ~15 Mio. EV and the highest (100%) for the EUCO30 in 2050 scenario with ~199 Mio. EVs.

In Figure 6.15 and Figure 6.16 results of the **cumulative generation** for nine winter days in Germany with occurrence of loss of load in this period are given. For the base scenario with no adaption of EV charging given in Figure 6.15, even if the $CO_2$ price results in

[23] Appearance of EENS due to the fact that no capacity optimisation is realised for the integration of EV in the given scenarios, which means that the power plant complex is a constant input parameter

significantly higher marginal cost of coal power plants, they are still necessary to cover the demand in peak load hours.

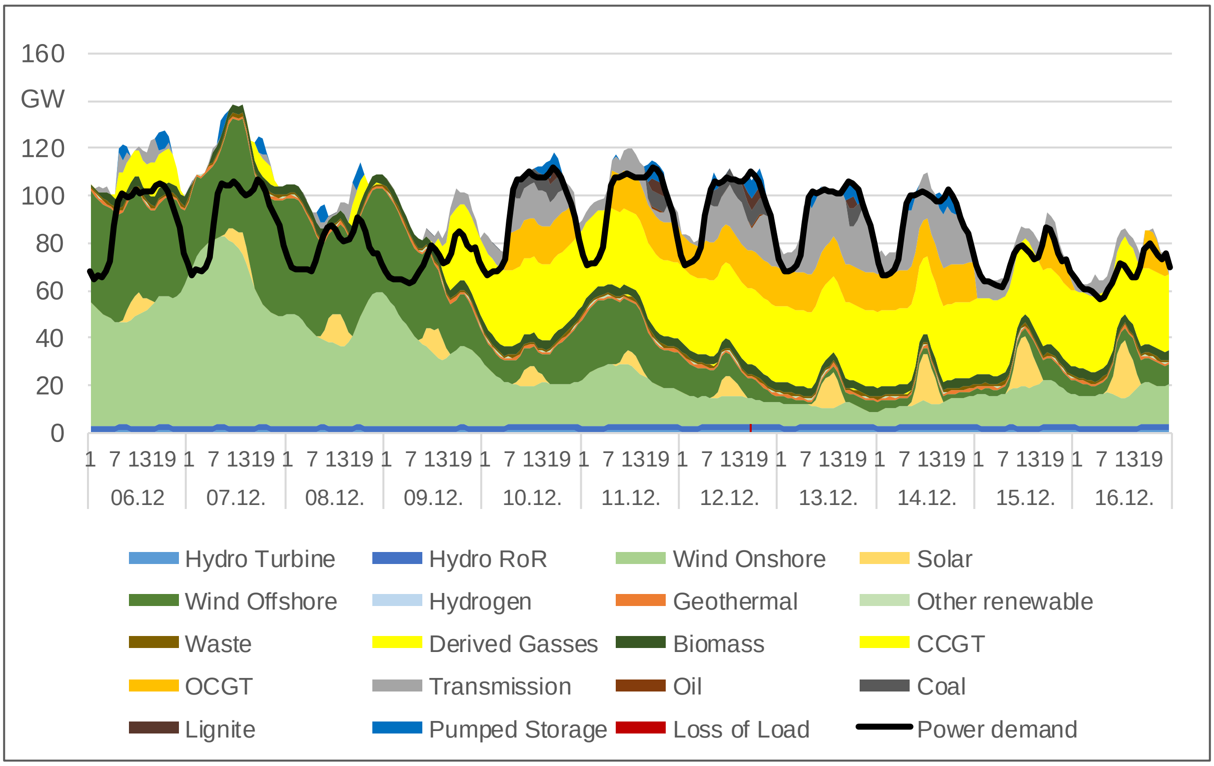



*Figure 6.15 : Cumulative generation in Germany for base scenario in EUCO30 in 2050*

For the RTP charging scenario, given in Figure 6.16, in the same period, no usage of coal power plants is necessary, not even in peak load hours. Furthermore, due to the shift of EV charging, short operating periods of conventional power plants can be avoided, which is beneficial in terms of overall system costs, as short operating periods increase the marginal costs due to higher start-up costs of power plants.

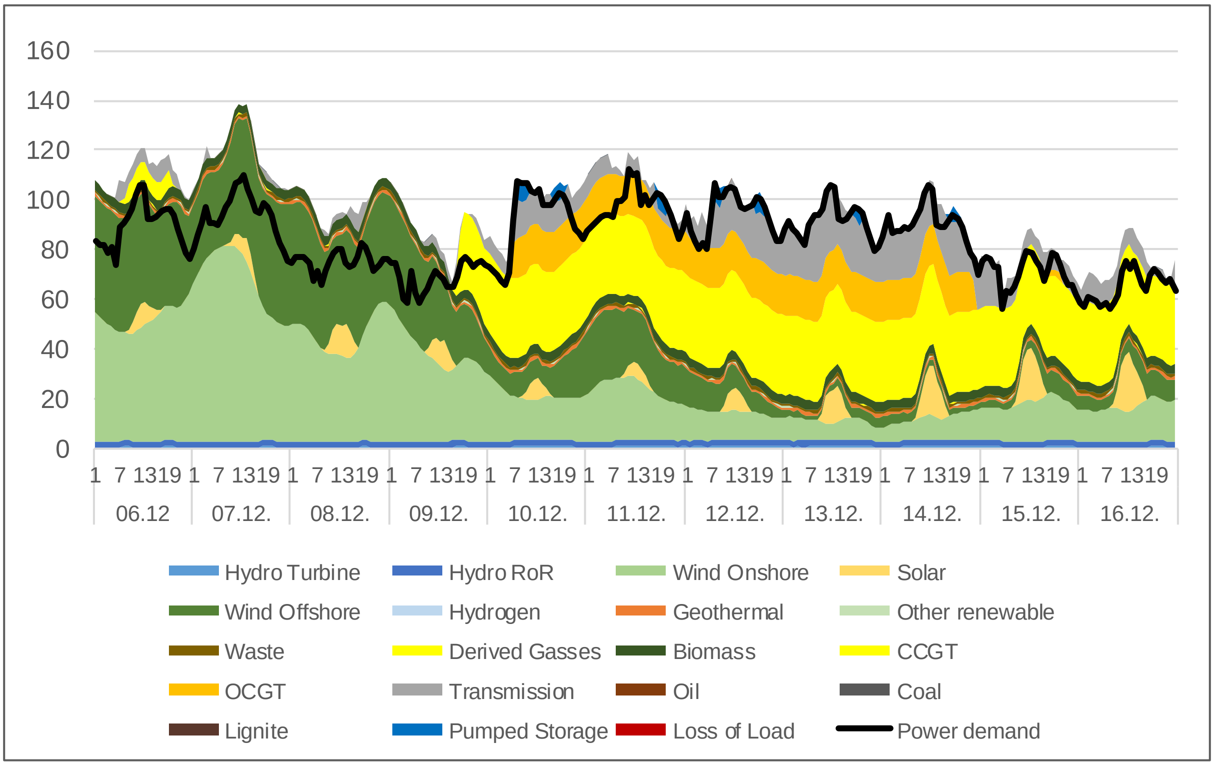



*Figure 6.16: Cumulative generation in Germany for RTP scenario in EUCO30 in 2050*

In 2030, the base load is mainly covered by coal power plants, whereas gas turbines and biomass cover the demand in hours of peak load. Contrarily to the RTP-based charging in 2030, the RTP-based charging in 2050 directly results in a reduction of $CO_2$ emissions due to the higher $CO_2$ price. The usage of conventional power plants highly depends on the merit order in the given scenarios. Considering further aspects, the RTP-based charging results in a decrease of ramping up or down generation units, which means less mechanical stress and a higher efficiency of the power plants.

**Summary**

In 2030, according to projections, electric vehicles would still play a limited role (up to 2% of EU overall electricity demand), but by 2050 electricity may represent an important share of passenger cars energy demand (34%) and of overall EU electricity demand (10%). Considering a higher $CO_2$ price over time, the shift in electric vehicle charging demand goes along with a drop in $CO_2$ emissions -7.9% for EU28 countries (-8% for EU28+6 countries), as the merit order is headed by renewable energy sources, biomass and low-carbon gas-fuelled power generation capacities. At the same time the mean marginal generation costs for EU28 countries are reduced by around 13% in 2050 compared to the base scenario (-12% for EU28+6 countries). The power generation mix heads to an increased utilisation of low carbon base load power plants. The utilisation of coal power plants can be avoided due to RTP-based charging.

In conclusion, an important potential of flexibility for the power system is given by EV in 2050. The impact of different EV charging behaviour on the power system is mainly driven by the share of passenger car electricity demand in overall electricity demand.

### 6.2.3. *Part III – Going beyond RTP charging*

The third part of the results is an in-depth assessment of the RTP charging scenario considering two distinct sensitivities. It is therefore separated into two sections. The main section discusses the vehicle-to-grid approach for the EUCO30 in 2030 and 2050 scenario, in order to see the impact on the power system and especially the dispatch of power plants. The second section gives an overview on the grid compliant charging in EUCO30 in 2030 scenario including an outlook on potential further studies.

**Vehicle to Grid Approach**

As mentioned earlier, the vehicle-to-grid approach allows bidirectional flows between grid and EV. In Figure 6.17 and Figure 6.18, net consumption **profiles** of EVs are given as example for France for three days (Mo/Tu/We) in 2030 and 2050. Negative net consumption thereby, indicates discharging of EV into the grid (production). Again, the residual load is an indicator for charging and discharging periods. In 2030, the residual load is positive in all hours of the days (cf. Figure 6.17). The charging again is preferred in hours of lowest residual load, whereas discharging into the grid occurs in hours of high residual load, i.e. in particular in early evening hours.

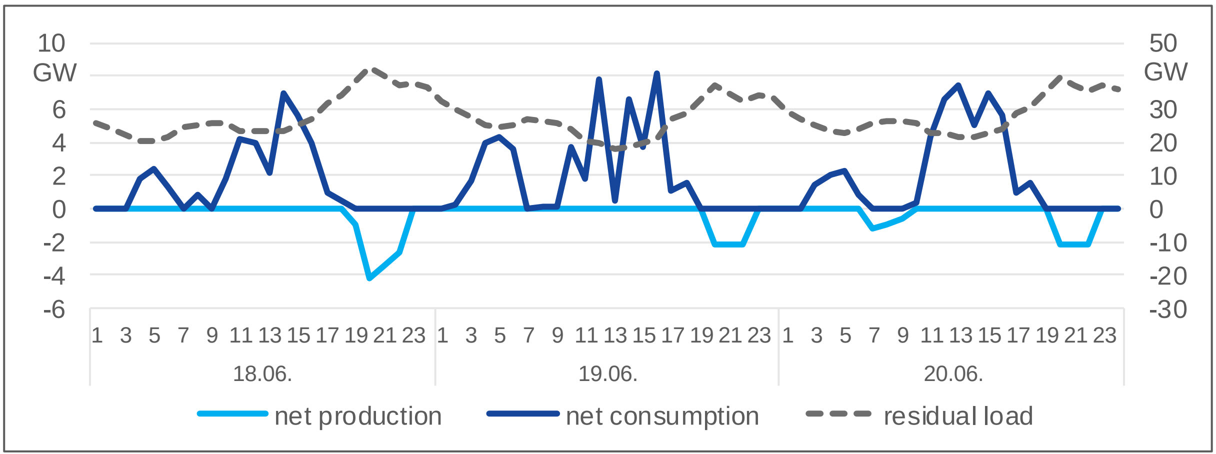



*Figure 6.17: Profiles of V2G for three days in summer 2030 in France and corresponding residual load (right y-axis)*

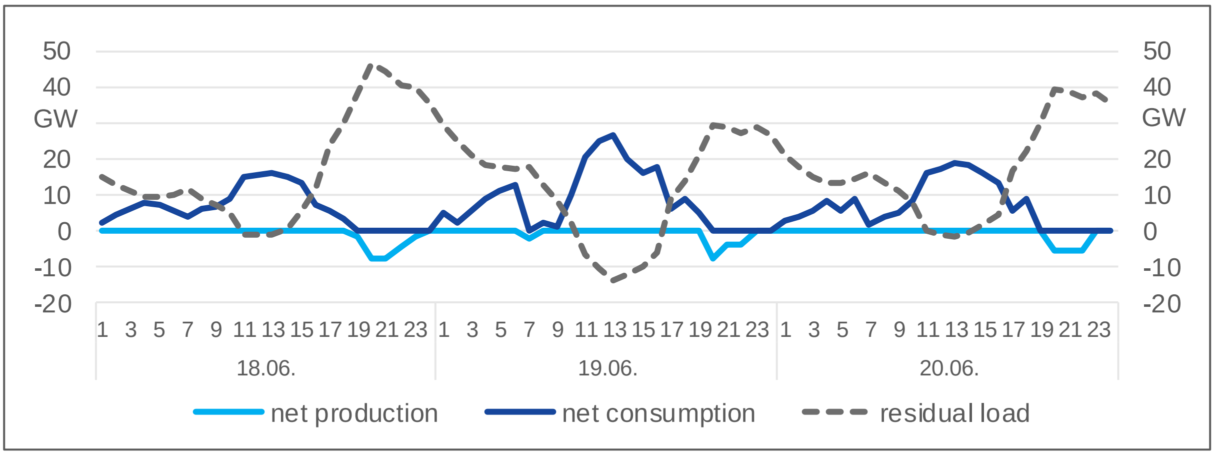



*Figure 6.18: Profiles of V2G for three days in winter 2050 in France and corresponding residual load (right y-axis)*

In 2050, the residual load becomes negative (i.e. entire load is covered by renewables) due to the higher share of RES in 2050. The charging behaviour in 2050 compared to the one in 2030 is better aligned to the residual load, which means consumption in periods of low and production in times of high residual loads, caused by different aspects: (1) there is a significantly higher range of residual load (52 GW compared to 25 GW) in the given period and (2) the higher share of EV demand from the overall electricity demand results in an increased flexibility potential. As V2G is based on the RTP charging scenario with the ability of EV discharging to the grid, the generation dispatch of the vehicle-to-grid scenario is compared to the RTP charging scenario for both 2030 and 2050. The **difference in generation** is given in Figure 6.19.

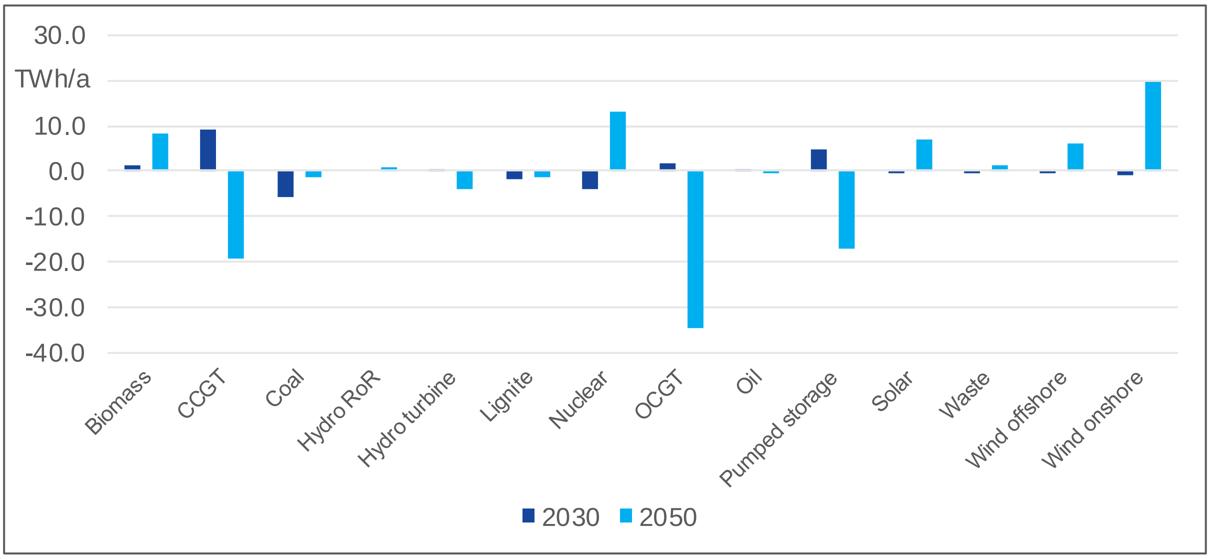



*Figure 6.19: Difference in generation between V2G and RTP scenario for EU28 countries*

V2G has significant impact on the dispatch of generation capacities. It implies in 2030 and 2050 a further decrease of power production from flexible power plants like gas turbines. On the other hand, the infeed from base load power plants as well as RES for the V2G approach increases compared to the RTP charging scenario. In 2030, baseload plants are represented by nuclear, lignite and coal. In contrast, $CO_2$ price-driven fuel switch leads to enhanced utilisation of biomass in 2050. The impact of V2G on the **$CO_2$ emissions** in EUCO30 in 2030 scenario is negligible, but in 2050 the emissions are reduced by 2.5% for EU28 countries (EU28+6: 2.6%) compared to RTP-based charging. The resulting decrease in marginal cost is negligible even in 2050, but the impact on curtailment is significantly high (- 17.7% in 2030 and – 19.7% in 2050) for EU28 as well as EU28+6 countries. Thus, the V2G approach further facilitates the integration of RES into the power system.

**Grid Compliant**

Charging in the RTP scenario compared to the immediate scenario can increase the national system peak load because the scope of the optimization is purely market-based. This can be seen in particular for Italy in Figure 6.20. The peak load of the system is an indicator for increased stress of grids and should therefore be observed. As the scope of the study does not include a detailed grid modelling, a simplified approach via capped charging simultaneity is used to assess this indicator.

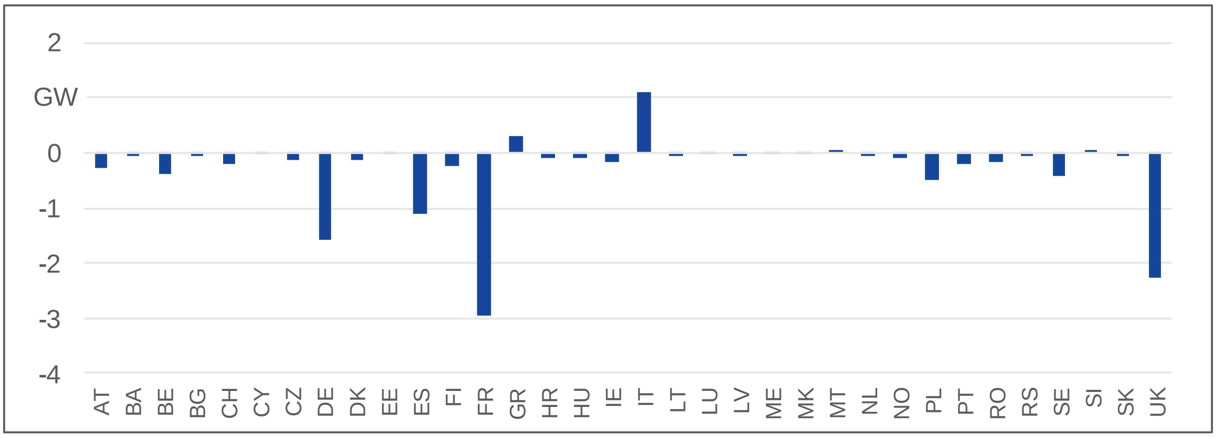



*Figure 6.20 : Difference in peak load between RTP and immediate charging in EUCO30 in 2030 scenario*

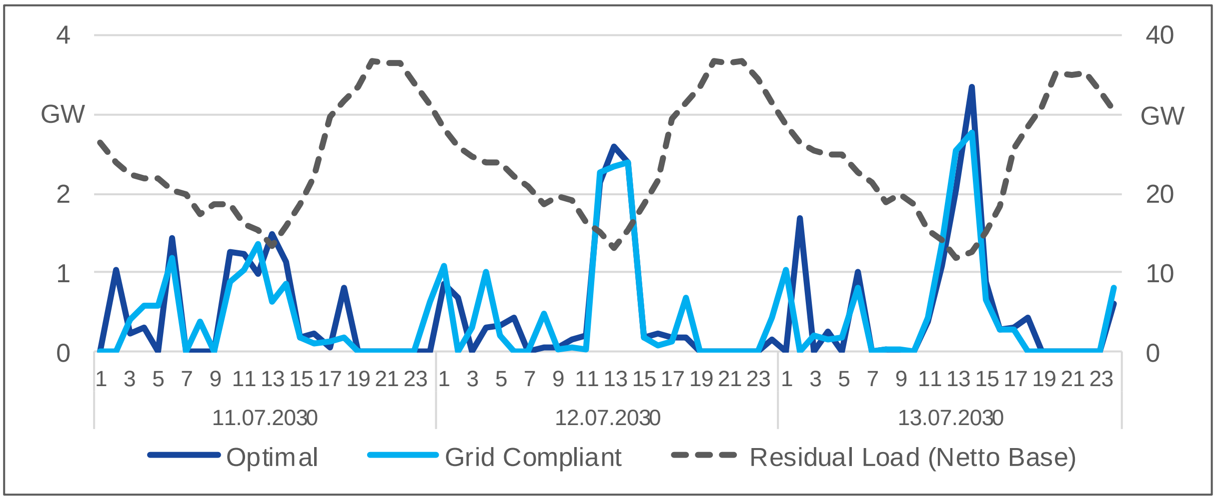



*Figure 6.21: Charging profile of RTP and grid compliant charging in Italy*

For the grid compliant scenario, each type of EV (BEV and PHEV, home and work) in each country is limited to a 40% charging simultaneity[24]. The profiles of the RTP and the grid compliant scenarios as well as the residual load for three days in Italy are given in Figure 6.21.

Summarizing these results, a purely market-based approach is not necessarily useful from a grid perspective and might increase grid stress, resulting in a potential need for grid reinforcement or other measures to address congestion such as the use of flexibility products from grid operators. This should potentially be taken into account in ToU- as well as RTP-price signals, e.g. via time varying network tariffs. To assess this aspect in detail, a modelling of transmission as well as distribution grids is necessary, but not part of this study. Therefore, in further METIS studies the distribution and the transmission grid will be modelled in detail to assess the impact of a market-based charging on the need for grid expansion measures and the grid usage in general.

[24] Beforehand, no limitation of charging simultaneity was given.

**Summary**

The vehicle-to-grid approach adds storage capacities to the power system and therefore, enables discharging into the grid, which facilitates variable renewable energy sources integration. This can be observed by a reduction of curtailment (nearly 20% in 2050 for EU28 as well as EU28+6 countries). In 2030, where the residual load is positive in all the times, discharging often appears in the early evening hours but nevertheless, the reduction of $CO_2$ emissions is negligible. In 2050, in some hours of the days, the residual load becomes negative. Considering the higher range of residual load in 2050, the high $CO_2$ price and the increased potential of flexibility from EV compared to 2030 leads to a reduction of $CO_2$ emissions (-2.6% for EU28 countries compared to real-time price scenario).[25] Compared to the reduction of production costs of real-time price-based in 2030, the production costs are further reduced by some 182 million € or 0.3%. In sum, this means a reduction of production costs of 910 m € for vehicle-to-grid under a real-time pricing scheme compared to immediate charging.

Real-time price-based charging may increase peak load in certain countries and thus stress for distribution and transmission grids (e.g. in Italy). Grid-compliant charging that limits the simultaneous charging of EV might reduce the need for additional grid reinforcement. Yet, for a robust conclusion it is necessary to perform a detailed grid modelling. Thereby, it can be assessed whether it is better to rather reinforce grid capacities and allow for a pure market-based optimization or whether grid aspects should be included into the tariff-signal that serves for electric vehicle charging optimization.

[25] Next to the usage of EV batteries as a flexibility in day ahead market, the may be used for reserve procurement in future as well like in [13] and [14].

# 7. POLICY RECOMMENDATIONS

## 7.1. RESULTING POLICY RECOMMENDATIONS

1. Negative impacts resulting from uncoordinated charging while electric vehicle penetration increases can be avoided by introducing time-varying tariffs like time-of-use or real-time prices. This recommendation is fully in line with Article 11 of the proposed recast of the Electricity Market Directive (COM(2016) 864 final/2, [16]), enabling consumers direct participation in the market via dynamic electricity pricing contracts. These schemes are recommended to be established as insurance policy that the system can cope when the electric passenger cars are deployed on large scale.
2. To capture the full benefits of additional system flexibility created by electric vehicles and ensure a fully system-compliant integration, place should be given to new actors, such as aggregators that can bundle the shiftable load of all flexible consumers and/or to establish real-time pricing for final costumers themselves. This echoes the relevance of paving the way for aggregators, as required by Member States through Article 17 of the proposed recast of the Electricity Market Directive [16].
3. As time-of-use-/real-time price-based electric vehicle charging requires communication and data flow between the consumer and the suppliers or aggregators as well as grid operators, it is important to ensure an enabling framework and acceptability for such new IT technologies, e.g. by
    a. ensuring necessary roll-out metering and IT technologies and
    b. ensuring the establishment of secure data exchange and storage in order to address consumers' privacy and data protection concerns.

   Article 19 and 20 of the proposed recast of the Electricity Directive [16] take this line by calling for a comprehensive implementation of smart metering systems compliant with a set of pre-defined functionalities as well as specific levels of cybersecurity protection.
4. Electric vehicle smart charging should finally not only be considered as a means of reasonable integration of electric vehicles in the power system, but as a resource of system flexibility (e.g. for RES integration) by making use of the batteries installed in electric vehicles as important system storage potential. Paving the way for battery utilisation for system services via vehicle-to-grid technology requires dedicated IT-based communication and management solutions as well as access for electric vehicle owners or intermediary entities to the respective markets for system services. The proposed recast of the Electricity Regulation (COM(2016) 861 final/2, [17]) backs this development by calling for enhanced investments in infrastructure supporting the integration of variable and distributed generation. It further calls for effective scarcity prices that encourage market participants to be available when flexibility is most needed in the power system.
5. As purely electricity price-based optimization of charging behaviour entails the risks of enhanced stress situations for distribution and transmission grids, the benefits

from smart electric vehicle charging need to be contrasted with related grid reinforcement requirements. Grid constraints could be taken into account in time varying tariffs e.g. via time-varying network charges. The relevant possibility is clearly spelled out in the proposed recast of the Electricity Market Directive, but its actual use will depend on decisions of individual Member States.

## 7.2. LIMITATIONS OF THE ANALYSIS

In the present study, the capacities of power plants are given based on REF16/EUCO30 scenarios and no optimization or rather investigation in new capacities is realised for example to avoid expected energy not served. In general, no costs for the smart integration of electric vehicle are considered but the benefits of integrating them in a smart way are determined. For the vehicle-to-grid approach, the modelling of electric vehicle does not include battery ageing and related costs that may appear. Merely, conversion-related efficiency losses are considered in the modelling. Finally, it is difficult to say whether the system-related gains from vehicle-to-grid are higher than the additional costs related to the speed of battery capacity erosion. As a limitation of the analysis, it is a rather conservative approach to not consider the possibility of fast charging at public points. Furthermore, in this study a purely electricity price-based approach is used to optimize the charging behaviour and the grid aspect in considered in a simplified way limiting the charging simultaneity by electric vehicle type and country.

As the integration of electric vehicles in the EU power system represents a complex topic that can be analysed under varying aspects, the scope of the study is subject to a set of limitations and simplifying assumptions. For instance, the analysis focusses exclusively on the day-ahead market, without taking into account potential interaction with other market segments, such as intraday or reserve markets. As the projection horizon of the analysis lasts until the year 2050, technology and behavioural assumptions are subject to high uncertainty. Future driving patterns are difficult to predict as new car ownership and driving concepts (e.g. car sharing, autonomous vehicles) are likely to enter the market. In this study, it is assumed that driving patterns remain unchanged.

## 7.3. OUTLOOK

As a result of the in-depth assessment of the RTP charging scenario, it would be necessary to model the transmission as well as the distribution grid to further analyse the impact of (smart) EV integration on grid usage and reinforcement (METIS 2). By modelling the grid topologies in detail, information on the loading as well as possible overloading of lines and voltage magnitudes can be investigated even in situations with outages. From this investigation, the need for grid reinforcement and grid expansion can be derived.

From the market aspect, a joint capacity optimization should be implemented to see how much peak load capacity can be avoided or may have to be installed from being assessed due to electric vehicle integration. Next to the grid and the market-based approach, a battery optimal approach like in [15] to reduce the impact of smart charging on battery ageing is conceivable and furthermore, may incentivise electric vehicle owner to change their charging behaviour.

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# 9. ANNEX

## 9.1. ASSUMPTIONS ON CHARGING STRATEGIES AND SCENARIOS

*Table 9.1: Characteristics of modelled charging strategies*

| | Charging strategy | Immediate | ToU | RTP |
|---|---|---|---|---|
| Modelling of Charging Profiles | Profile determination | exogenous | exogenous | endogenous |
| | Week-/weekend day | Weekdays or rather weekend days have similar profile | | Profile depending on hourly electricity price |
| | Definition | Static profile with charging after arrival | Static profile based on average hourly marginal costs | |
| | Participation in travel (from number of EV) | 70% | | |
| | Charging capacity | Maximum 3.3 kW | | |
| | Geographical resolution | Same charging profile for each country shifted according to daily activities | Individual charging profile for each country | |
| | Charging location | 50% of EV charge at home, 50% of EV charge at work | | |
| Charging behaviour | Charging priority | Without other restrictions, charging as early as possible | | |
| | Charging status | Fully charged battery at departure | | |
| | V2G | | | Efficiency losses: 20%<br>Maximum discharging equal to mean daily demand |
| | GC | | | Limitation of charging simultaneity to 40% |

*Table 9.2: Scenario assumptions*

| Scenario | Immediate | ToU | RTP | Mixed |
|---|---|---|---|---|
| Share of charging strategies | 100% Imm. | 10% Imm.<br>90% ToU | 10% Imm.<br>90% RTP | 50% Imm.<br>40% ToU<br>10% RTP |

## 9.2. Input data

### 9.2.1. *EV electricity demand*

#### *9.2.1.1 REF16* in *2030*

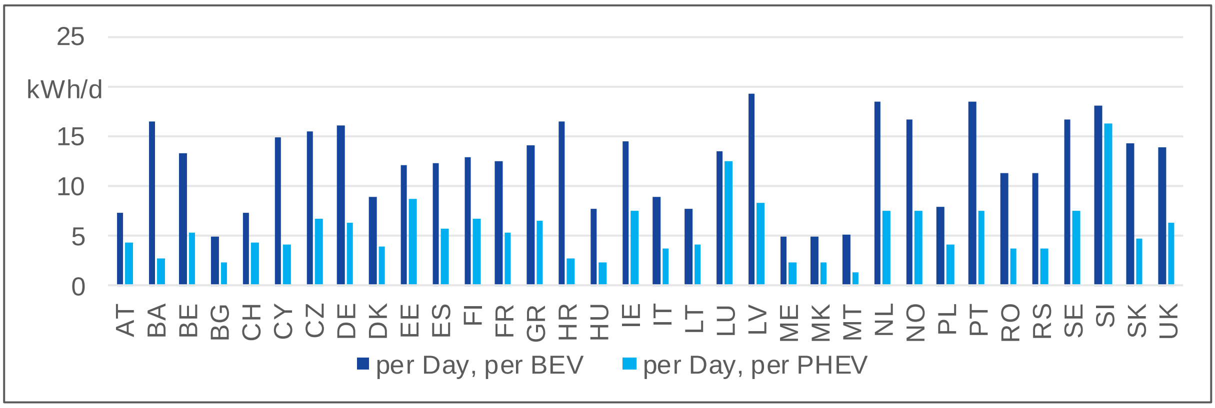


*Figure 9.1: Daily demand per EV per day in REF16 in 2030 scenario*

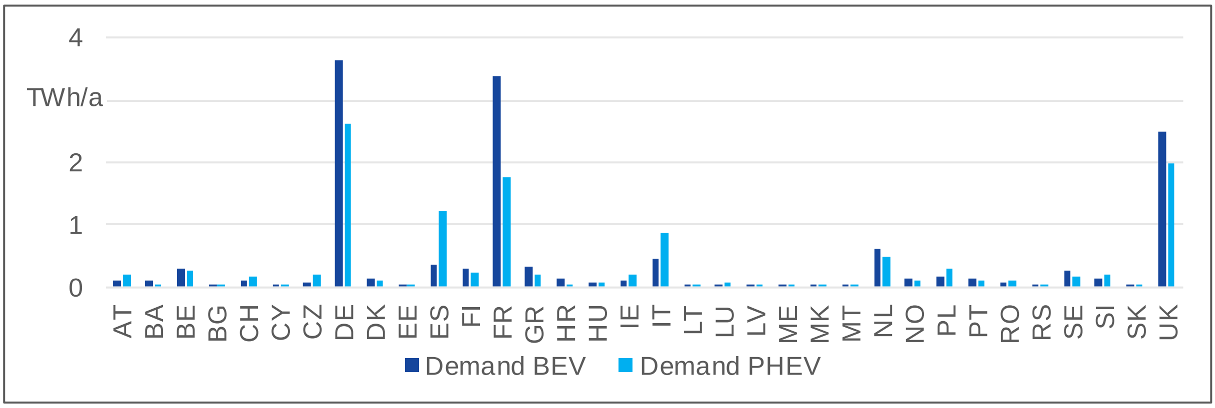


*Figure 9.2 : Annual demand of EV fleet in REF16 in 2030 scenario*

#### 9.2.1.2 *EUCO30* in *2030*

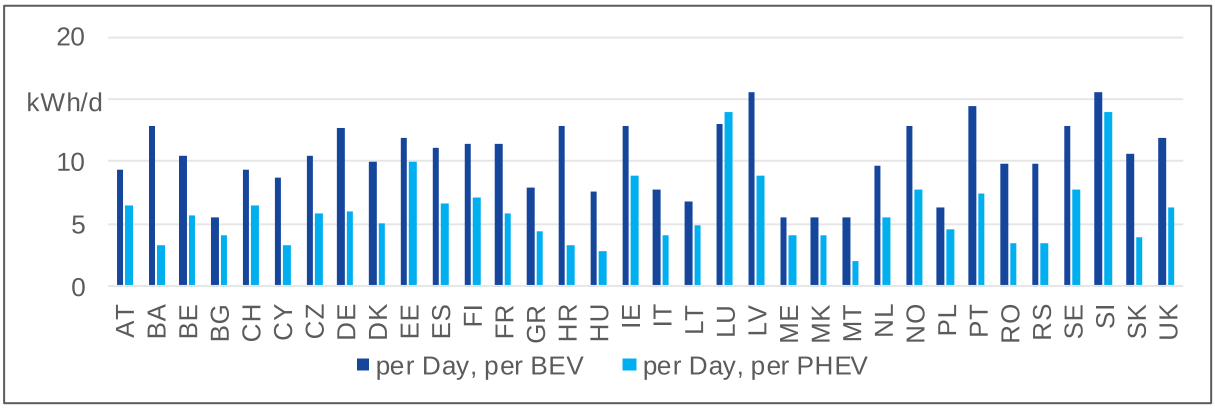


*Figure 9.3 : Daily demand per EV per day in EUCO30 in 2030 scenario*

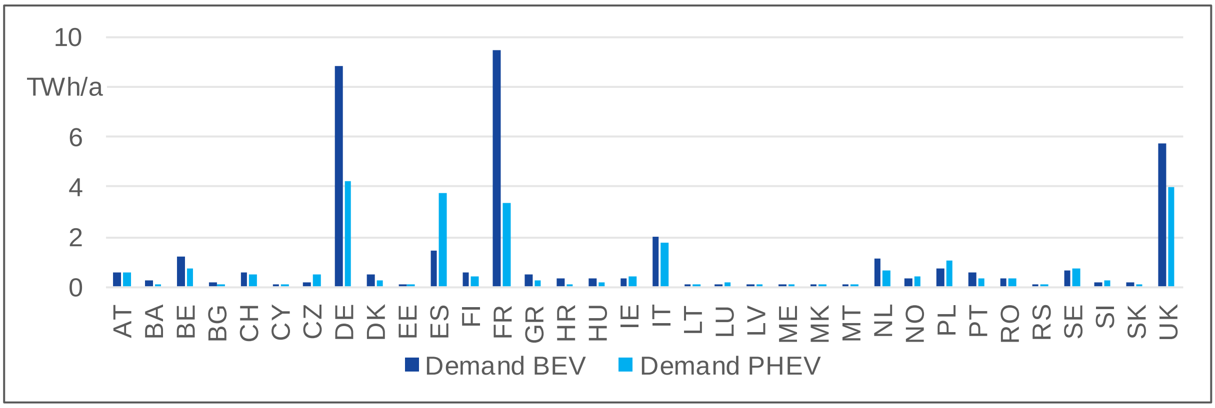


*Figure 9.4: Annual demand of EV fleet in EUCO30 in 2030 scenario*

#### 9.2.1.3 *EUCO30* in *2050*

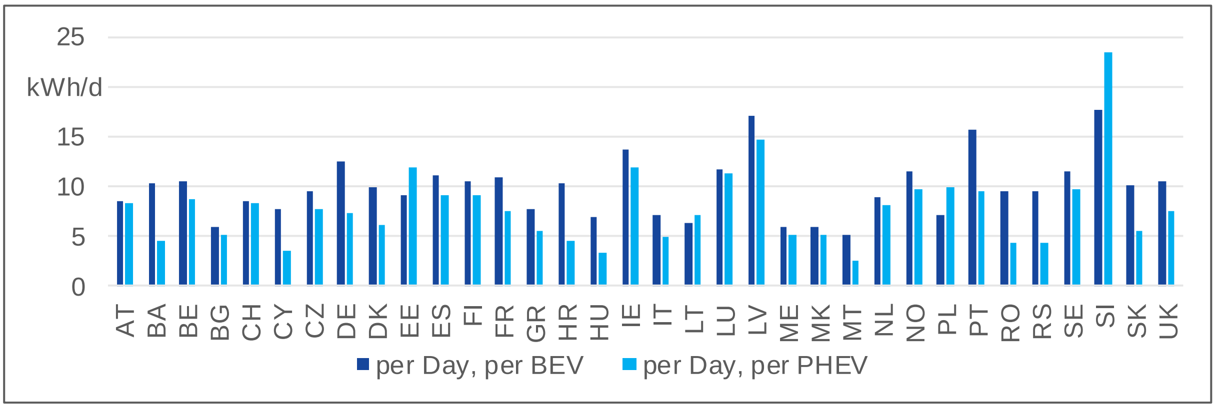


*Figure 9.5: Daily demand per EV per day in EUCO30 in 2050 scenario*

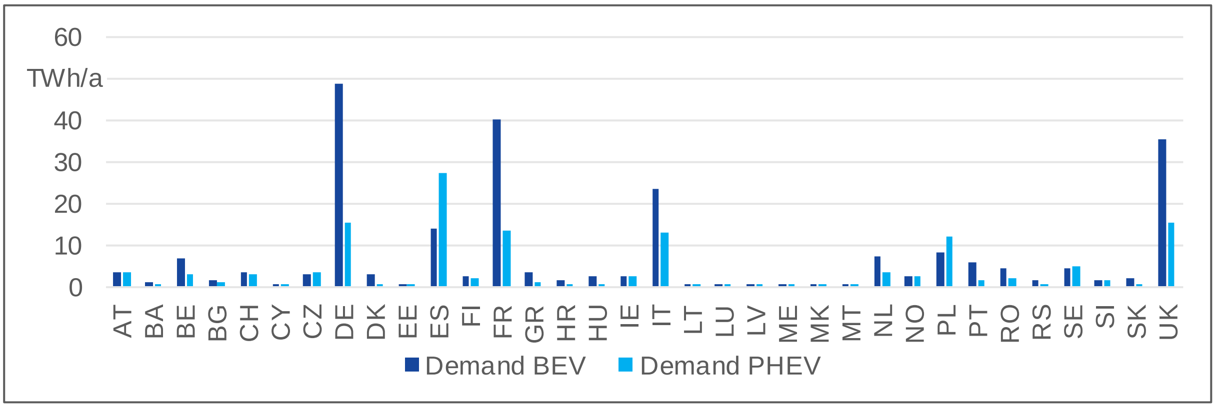


*Figure 9.6: Annual demand of EV fleet in EUCO30 in 2050 scenario*

### 9.2.2. *TOU-BASED CHARGING PATTERNS UNDER THE EUCO30 IN 2030 SCENARIO*

| Country | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 |
| RO | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 |
| CY | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| FR | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HR | 0 | 0 | 0 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MT | 0 | 0 | 0 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BA | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BG | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HU | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IE | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LT | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MK | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RS | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SE | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SK | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NL | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AT | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CZ | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DE | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| UK | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BE | 0 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LV | 0 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NO | 0 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PT | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DK | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PL | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 1 | 1 |
| FI | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 |
| SI | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 |
| EE | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LU | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ME | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GR | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IT | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Figure 9.7: Low (0) and high (1) price periods under the EUCO30 in 2030 ToU-based Charging scenario for summer weekdays*

| Country | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CY | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ES | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| RO | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| NL | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HR | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AT | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BG | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CH | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| FR | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LT | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RS | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DK | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| FI | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| NO | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| BE | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PT | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| BA | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CZ | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DE | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HU | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| IE | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LV | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MK | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MT | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SE | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SK | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| UK | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PL | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 |
| SI | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 |
| LU | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| ME | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| EE | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 |
| GR | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| IT | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Figure 9.8: Low (0) and high (1) price periods under the EUCO30 in 2030 ToU-based Charging scenario for winter weekdays*

## 9.3. Results

### 9.3.1. *Results of EU28+6 Countries*

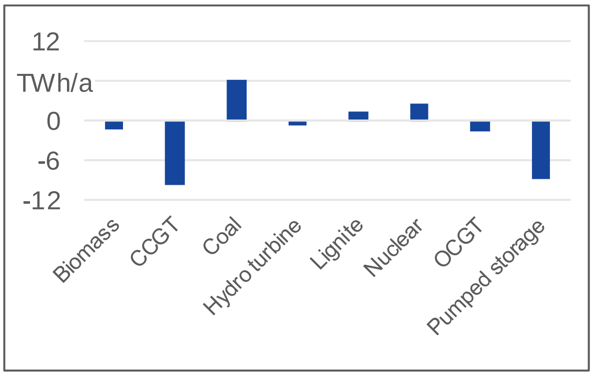


*Figure 9.9: Difference in generation between RTP- and immediate scenario (EU28+6 countries)*

*Table 9.3: Main data of REF16/EUCO30 Scenarios ($CO_2$ emissions prior to EV charging optimisation) for EU28+6 countries*

| | Additional electricity demand by EV | Share of electricity in passenger cars energy demand | Number EV in EU28+6 countries [M.] | $CO_2$ emissions in power generation sector [Mt] | Share RES overall in production [%] |
|---|---|---|---|---|---|
| REF16 2030 | 26 TWh 0.8% | 1.4% | 15 | 738 | 42.6 |
| EUCO30 2030 | 63 TWh 2.1% | 3.9% | 38 | 687 | 49.5 |
| EUCO30 2050 | 372 TWh 10.4% | 34.3% | 199 | 207 | 64.4 |

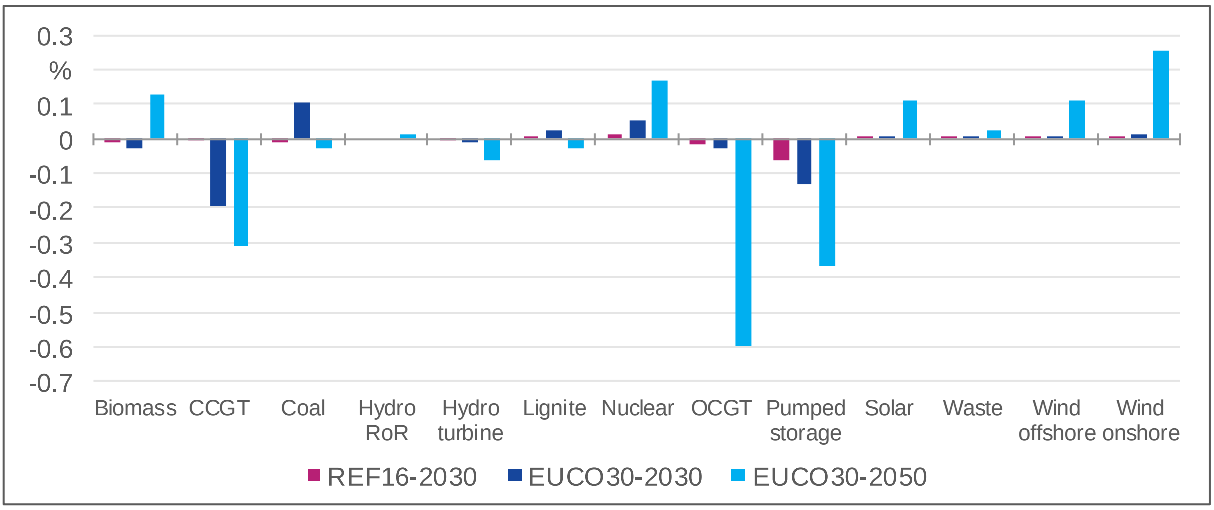


*Figure 9.10: Difference in generation between RTP- and base scenario for all REF16/EUCO30 scenarios as a sum of EU28+6 countries*

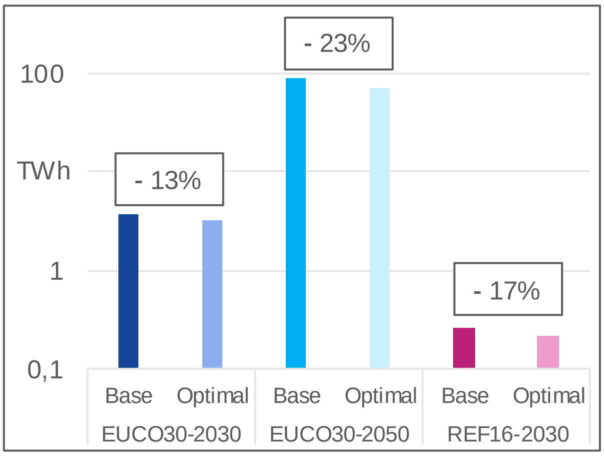


*Figure 9.11: Curtailment in different REF16/EUCO30 scenarios due to RTP-based charging*

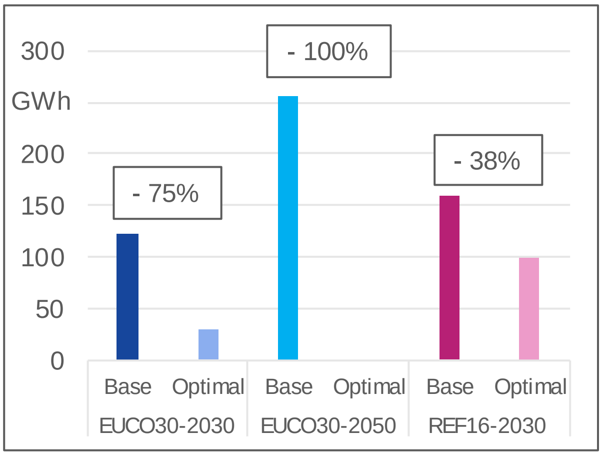


*Figure 9.12: Difference of Expected Energy not Served in all REF16/EUCO30 scenarios*

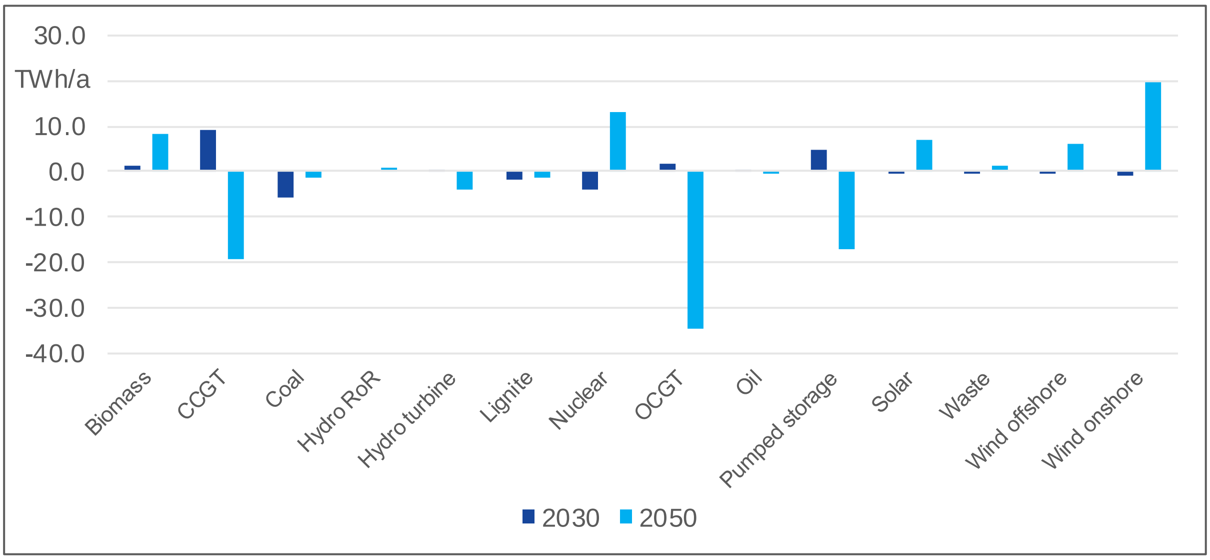


*Figure 9.13: Difference in generation between V2G and RTP scenario for EU28+6 countries*

### 9.3.2. Capacity Factors for selected Generation Technologies

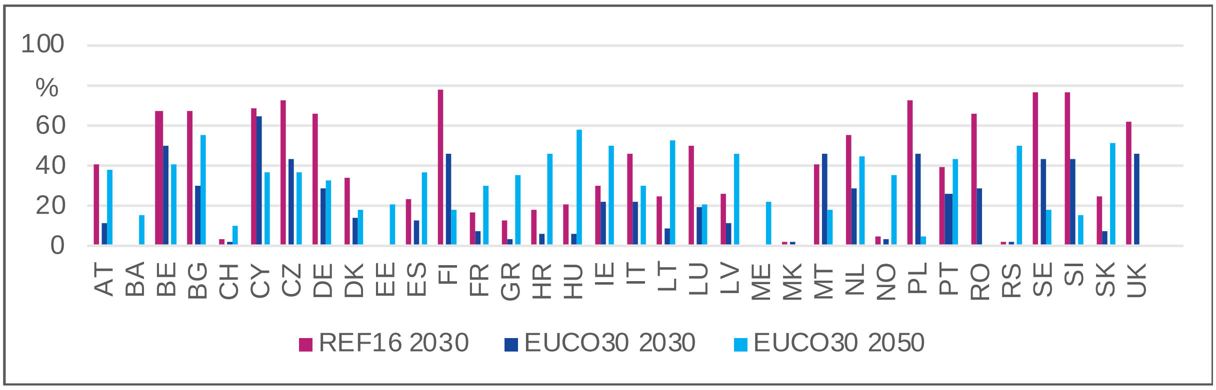


*Figure 9.14: Capacity Factor of CCGT in RTP Scenario for all REF16/EUCO30 Scenarios*

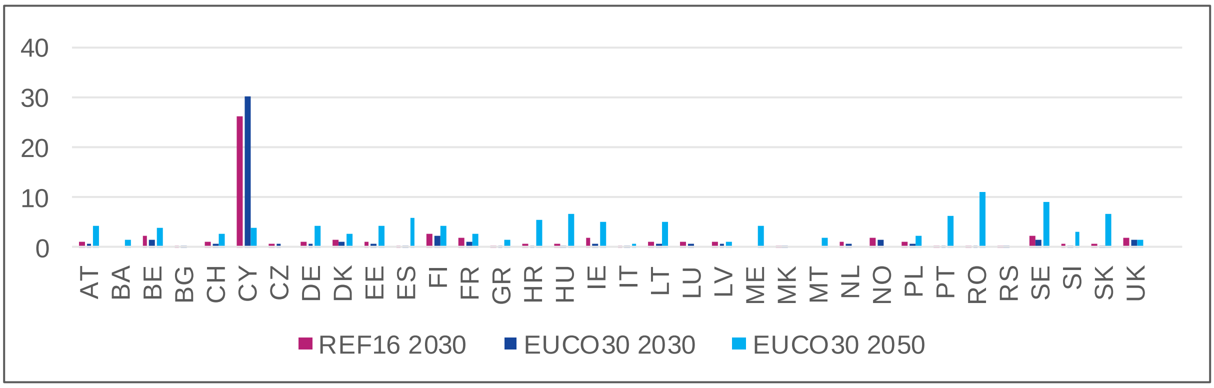


*Figure 9.15: Capacity Factor of OCGT in RTP Scenario for all REF16/EUCO30 Scenarios*

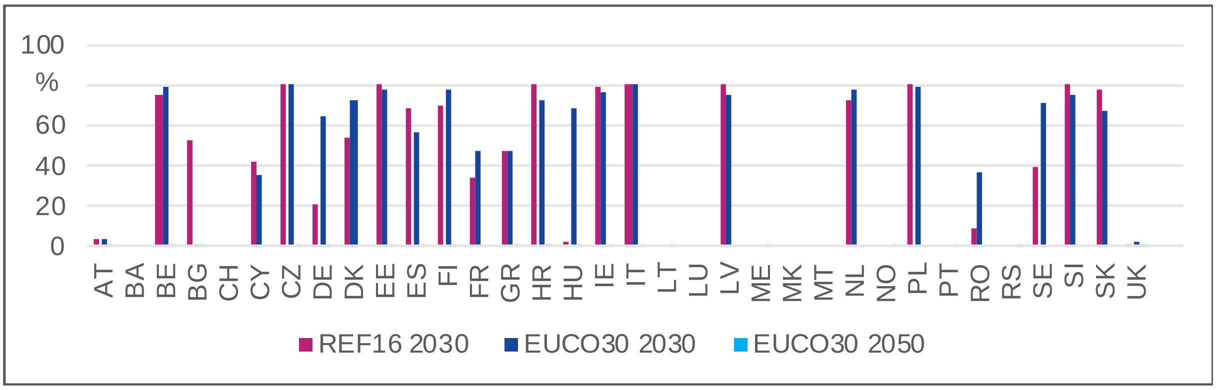


*Figure 9.16 : Capacity Factor of Coal in RTP Scenario for all REF16/EUCO30 Scenarios*

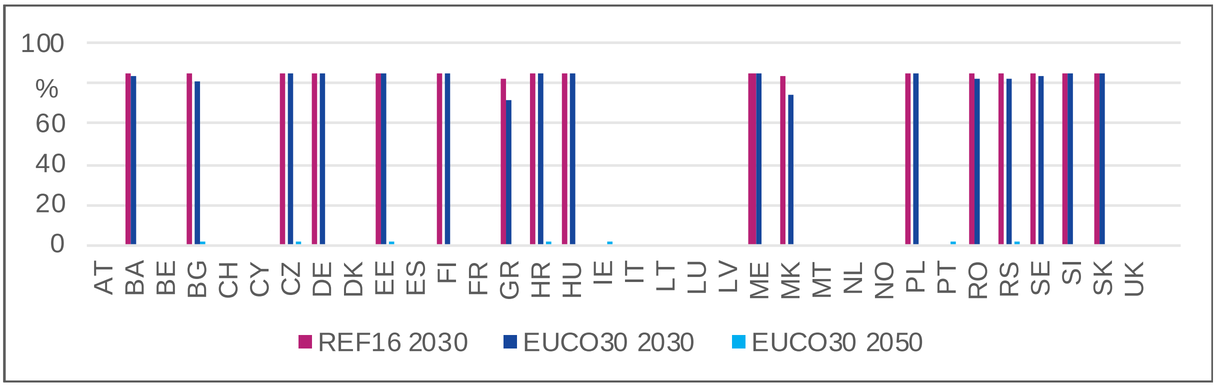


*Figure 9.17 : Capacity Factor of Lignite in RTP Scenario for all REF16/EUCO30 Scenarios*

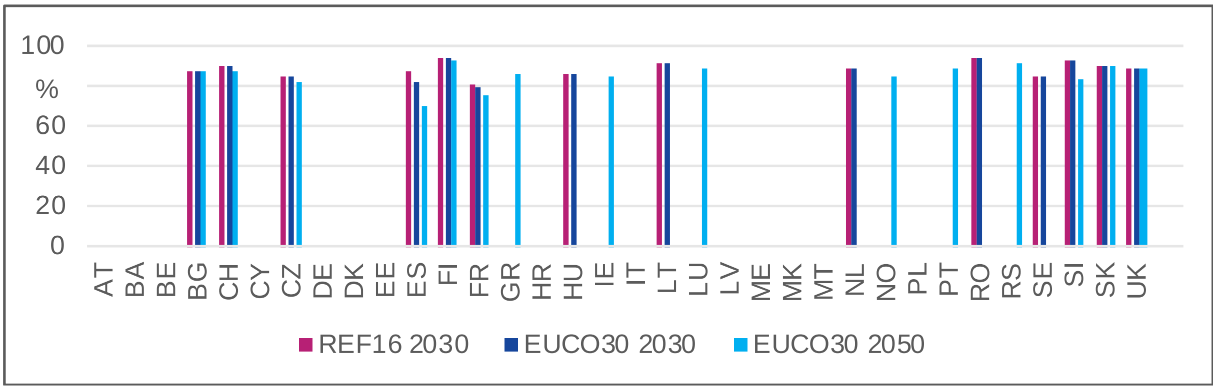


*Figure 9.18: Capacity Factor of Nuclear in REF16/EUCO30 Scenarios*