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Integration of distributed generation and electric vehicles into Turkish distribution grids until 2038

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Executive summary

Energy systems worldwide are undergoing a profound energy transition with several key dimensions, such as the integration of variable renewable energy sources (RE) into the power grid. This shift is accompanied by a rising share of electric vehicles (EVs), whose charging requirements put additional stress on electricity distribution grids.

This transition necessitates a significant transformation of infrastructure, presenting numerous challenges for distribution system operators (DSOs) in planning, investment and financing. As the system becomes more decentralised, ensuring secure grid operation while complying with maximum current and voltage limits demands that DSOs take on new roles. Specifically, they must manage grid operation and congestion, develop grid expansion plans, and oversee substantial investment needs.

Additionally, effective data utilisation and the integration of consumption and generation flexibility are essential. All these challenges must be tackled simultaneously with limited resources (both human and financial).

Given these complexities, understanding the impact of increasing EVs and distributed generation (DG) on distribution grid operations is crucial. Grid modelling studies play a crucial role in navigating this landscape effectively, aiding in informed planning and management strategies. Moreover, they facilitate the development of regulatory frameworks and policies, tailored to support the sustainable grid integration of these new assets and addressing the evolving needs of DSOs amidst the energy transition.

This study delves into the Turkish distribution grid, analysing key areas of action and offering practical solutions for DSOs to navigate strategic decisions amid energy policy shifts. Utilising energy system models and planning tools, it comprehends the challenges and opportunities of infrastructure transformation. The study, a collaboration between the German Energy Agency (dena), Aplus Enerji and the Yildiz Technical University, emphasises integrated planning across electricity and mobility sectors to achieve efficient, cost-effective systems.

The first part of the study (part A), as prepared by Aplus Enerji and the Yildiz Technical University, comprises a grid modelling for one DSO region of the Turkish distribution grid. Türkiye is currently at a crossroads regarding its energy transition. While the country has achieved a substantial amount of renewable energy penetration over the last decade, the further integration of variable renewable and other decentralised assets into the energy system would necessitate a more flexible power system. This transition is already ongoing.

The aim of the distribution grid modelling is to contribute to the society-wide discussion and finding of solutions regarding distribution grid challenges. Comprehensive grid scenarios include real-world data for 2023 as well as projected data for 2030 and 2038. The scenarios depict the electrification of grid assets, specifically e-mobility and the expansion of decentralised renewable energy power plants, taking into account Türkiye's national policies and strategies as well as the Paris Agreement targets.

To tackle the increasing complexity of distribution grids, the approach is modular, covering three of the 21 DSO regions. The model is designed to be extendable to all DSO regions, other voltage levels and additional parameters. The data is gathered from one of the largest DSOs in Türkiye.

The 2023 case analysis of Türkiye's distribution system reveals that integrating electric vehicles (EVs) and distributed generation (DG) units, such as photovoltaic (PV) systems, is feasible and leads to manageable changes in line loading, voltage profiles and power losses. These changes remain within operational limits and in general, the 2023 grid demonstrates a positive adaptability to new technologies.

Looking ahead, the 2030 and 2038 case analyses project significant growth in the distribution system, with increased EV charging stations and DG units reflecting rising electricity demand and rapid EV adoption. By 2030, notable changes in line loading and voltage profiles are expected, along with increased power losses, despite some mitigation by DG units. A major concern is potential transformer overloading, with many transformers projected to operate above 80% capacity, highlighting the need for infrastructure enhancement and load management strategies. By 2038, these challenges intensify, with significant increases in line loading, power losses, and voltage drops below recommended thresholds, underscoring the necessity for robust grid infrastructure and improved voltage regulation to ensure grid stability amidst continued electrification and renewable energy adoption.

Based on the modelling results, the study provides regulatory recommendations in the following fields to address open issues and support new regulatory developments:

- **Proactively Plan and Execute Strategic Grid Investments**: Ensure timely development of grid infrastructure, including transformers, lines and topology, to meet energy transition needs and maintain operational excellence.

- **Develop Flexibility Markets**: Create markets where ‘prosumers’ can sell surplus energy or adjust consumption based on grid needs, aiding DSOs in managing power supply and demand efficiently.

- **Design Regulatory Frameworks and Implement Policies**: Establish supportive regulations and policies to facilitate energy trading, standardised tariffs and the development of smart grid infrastructure, ensuring the grid can handle growing EV demand and DG integration.

- **Incentivise Smart Consumer Behaviour**: Encourage dynamic pricing models and financial incentives for smart energy usage to optimise network operations, alleviate peak loads and enhance energy efficiency.

- **Allow a Reserve Capacity in Network Investments**: Plan for reserve capacity in network investments and adapt regulations to accommodate future EV loads, charging station requirements and additional technical standards to ensure grid stability and efficiency.

The second section of the study (Part B) was prepared by dena and includes insights into current German developments and experiences with the integration of flexible generation and loads as well as solutions for an optimised distribution grid planning and operation. Based on the lessons learned, these can also be made usable for Türkiye to address the challenges identified in grid modelling:

- **Leveraging Demand Side Flexibility**: Introducing regulatory changes to ensure that grid operators can actively manage the power consumption of controllable devices like heat pumps and EV charging stations during grid stress phases. This can be done by adhering to stipulated minimum output levels during peak shaving to maintain the operation of essential systems and prevent extensive curtailment.

- **Coordinated Grid Planning and Expansion**: Engage in predictive distribution grid planning by developing and submitting long-term grid expansion plans in a defined regular interval (e.g. two years), based on regional scenarios. These scenarios shall project the development of renewable energy plants and new loads, such as EVs, in the specific regions.

- **Lessons from Smart Meter Rollout**: Setting clear and realistic requirements regarding the safety and security of the smart metering system. The requirements should include existing metering systems available on the market but also foster new and innovative smart meter technology.

This study is developed within the framework of the Turkish-German Energy Partnership, which is implemented by dena and which has been successfully fostering the energy transitions in both countries since 2012. The results of the study are intended to help DSOs to make decisions on their future strategic direction and the challenges identified in achieving their goals within the current energy policy framework. In summary, this study provides DSOs with actionable insights and recommendations to navigate the technical and economic challenges of the energy transition, with a focus on regulatory frameworks, grid management, and policy support for sustainable grid integration.

Modelling study of future distribution grids in Türkiye: Impact analysis of electric vehicle integration and distributed generation in a real distribution grid in Türkiye (Part A)

1 Introduction to the Turkish Electricity Market

In the midst of the energy transition, conventional power systems are experiencing a significant overhaul. This transformation, primarily fuelled by the integration of novel renewable technologies into the structure of power systems, is largely motivated by environmental sustainability concerns. Key among these technologies is new generation loads, including electric vehicles (EVs), heat pumps (HP) and others, as well as distributed generation (DG) units based on renewable energy sources, which are at the forefront of driving this change.

1.1 Historical development of the Turkish electricity system

The historical development of the Turkish electricity distribution system has gone through several stages, marked by policy changes, regulatory reforms and efforts to modernise and expand the infrastructure. In the early years, the electricity sector in Türkiye was primarily state-owned and operated. The electricity distribution system was part of the vertically integrated structure where generation, transmission and distribution were managed by the state.

The 1970-1983 period may be referred to as the period of the Turkish Electricity Authority (TEK), which was founded in 1970 as a vertically integrated state-owned body, incorporating all electricity sectors other than distribution, which was under the responsibility of the municipalities until 1982.[1] Between 1993 and 2000, TEK was brought within the scope of the government privatisation program. Under the enactment of the decree of Law no. 513 in 1993, it was split into two different state-owned companies, the Turkish Electricity Generation Transmission Company (TEAŞ), responsible for both generation and transmission activities, and the Turkish Electricity Distribution Company (TEDAŞ), responsible for distribution and retail sale activities.[2] After the separation of the Turkish Electricity Authority, Build Operate Transfer (BOT), Transfer of Operating Rights (TOR) and Build Operate (BO) generation contracts were signed between private generation companies and TEAŞ or TEDAŞ, incorporating exclusive take-or-pay obligation clauses over 15-30 years. These commitments were again compensated by the Treasury through guarantees.

In 1996, The Ministry of Energy and Natural Resources initiated tenders for 29 distribution regions in the scope of a TOR. The winners were announced in the year 1998; however, transfers did not occur because of legal obstacles.

The Turkish Electricity Market reform began in March 2001 with the enactment of the Electricity Market Law (EML) No. 4628 to introduce competition and maintain sustainable growth for the market.[3] The Law aims to provide electricity consumers with continuous and high-quality electricity at an affordable price. The law established the Energy Market Regulatory Authority (EMRA, or EPDK in Turkish), which functions as an autonomous body responsible for regulating the electricity market.[4] Later, the functions of the EMRA were extended to cover the natural gas, liquefied petroleum gas (LPG) and petroleum markets.

In 2001, the Turkish Electricity Generation and Transmission Company (TEAŞ) was also unbundled into three parts: the Turkish Electricity Transmission Company (TEİAŞ), the Electricity Generation Company (EÜAŞ) and the Turkish Electricity Trading and Contracting Company (TETAŞ).[5] TEİAŞ was tasked with carrying out electricity transmission system and market operations; EÜAŞ was responsible for the operation of state-owned electricity generation capacity; and TETAŞ was established for executing wholesale electricity trade including the long-term PPA with BO, BOT and TOR companies. Between 2004 and 2006, TEDAŞ was restructured into a holding company and 20 regional subsidiaries for the implementation of privatisation in the distribution sector in line with the strategy outlined in 2004.[6] The privatisation of the distribution segments could only be concluded in 2013 as opposed to the 2006 end date set in the 2004 strategy.[7] Historical

[1] (Resmi Gazete, 1970)
[2] (Resmi Gazete, 1993)
[3] (Resmi Gazete, 2001)
[4] (Enerji Piyasası Düzenleme Kurumu)
[5] (Resmi Gazete, 2001)
[6] (Resmi Gazete, 2004)
[7] (Türkiye Elektrik Dağıtım AŞ, n.d.)

developments of the Turkish electricity system organisation structure are shown in Figure 1.

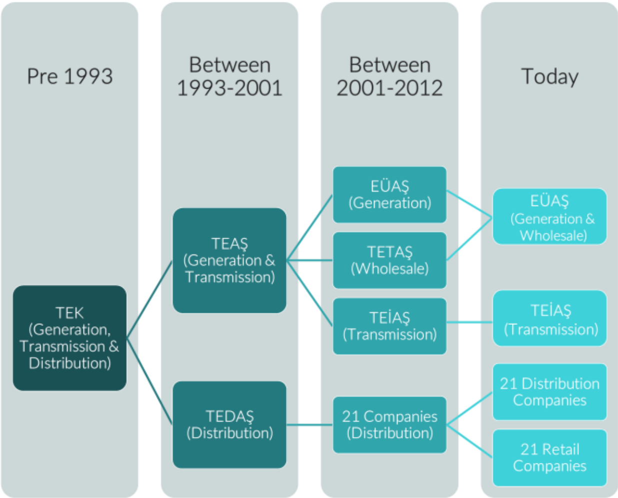

Figure 1. Organisation structure of the electricity system throughout the years

In 2013, distribution and retail sales activities were legally unbundled. Since the conclusion of the privatisation of the distribution sector in 2013, the sector has been controlled by 21 distribution companies active in their respective regions. Operational right contracts were signed between TEDAŞ and its distribution companies. These companies also have retail arms and the right to engage in retail electricity sales in their regions. The distribution regions are shown in Figure 2.

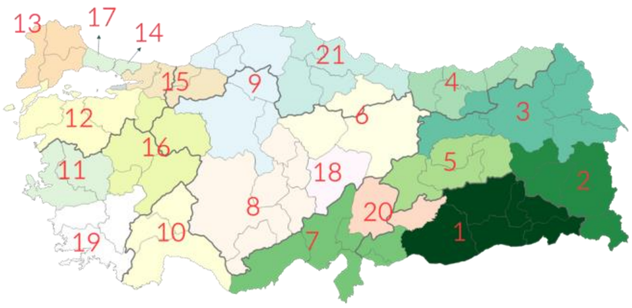

Figure 2. Distribution regions of Türkiye

1.2 Distribution grid reinforcement needs in Türkiye

As the world shifts towards a more sustainable and decarbonised future, characterised by a growing reliance on renewable energy sources, electrification of diverse sectors and the integration of advanced technologies, grid distribution faces a lot of challenges. During this global energy transition, the traditional landscape of electricity grid distribution is undergoing unprecedented transformation processes.

A streamlined planning and operation of distribution systems plays a crucial role in this transition. Below are key considerations in the planning and operation of distribution grids:

- Integration of Renewable Energy Sources
- Decentralised Energy Generation
- Electrification
- Energy Storage
- Smart Grid Technologies
- Demand Response Programs
- Regulatory Frameworks and Market Design

As Türkiye navigates the dynamic landscape of its energy sector, the increasing adoption of EVs and the proliferation of distributed energy generation assets pose significant challenges to the country's electric distribution companies. The surge in electric vehicle charging stations and decentralised power generation facilities has the potential to reshape the traditional electricity distribution system, requiring a strategic re-evaluation of infrastructure, regulatory framework and operational methodologies.

1.3 Distributed energy generation in Türkiye

The most important distributed energy generation source in the country is unlicensed solar power plants. These constitute a considerable volume of the total solar capacity in the country and help to increase renewable energy capacity. The Unlicensed Electricity Generation Regulation defines generation facilities that are exempt from the requirements to obtain pre-licenses, other licenses and establish a company. Before the regulation was updated in 2019, unlicensed electricity generators could sell their electricity generation without any consumption restriction.

The general feeling among the policymakers was that the pre-2019 scheme was initially designed to promote self-consumption, but this did not work because many of the investors found the high purchase guarantee levels to be much more lucrative and thus aimed to sell their generation into the grid instead of utilising it for self-consumption purposes.

Following the update in the regulation, unlicensed generation is now focused on self-consumption models rather than using the regulation as a tool to generate and sell electricity.[8] The previous and current situations

[8] (Resmi Gazete, 2019)

regarding the unlicensed regulation are summarised below.

Unlicensed Generation (Before 2019)

- 10 years fixed FiT from YEKDEM[9] (133 USD/MWh for solar)
- Mostly aimed at selling to the grid
- No net metering allowed
- 1 MW installed capacity limit

Unlicensed Generation (After 2019)

- Excess generation sold through the 'active energy cost' specified under the regulated tariff, which is announced by the EMRA for each quarter for each consumer type (for both rooftop and ground-mounted installations)
- Aimed at self-consumption for each consumer type
- Monthly net metering
- Consumption is limited to twice the contract power of the facility (in 2022, the installed power limit was increased up to five times)
- More than one consumption and generation facility can be grouped, and these are net-metered monthly without the condition of the distribution region being the same. The Amendment Regulation stipulates that generation facilities established according to Article 5.1/h of the Regulation can now be located outside the distribution area where the consumption facility is situated. Previously, investors were not allowed to establish renewable energy plants in distribution regions different to the one where the consumption point was located.
- The surplus energy generated above the previous year's consumption is transferred to YEKDEM as a free contribution. (For example, a subscriber consuming 1 million kWh of electricity in the previous year can sell a maximum of 1 million kWh to the grid after monthly offsetting. Generations exceeding 1 million kWh are not subject to payment). Household subscribers with an installed capacity of 50 kW or less will be exempt from the consumption limit.

There are several types of unlicensed electricity generation facilities in the country. However, the most important capacity comes from power plants meeting the criteria of a particular article within the regulation, namely "5.1.h", and the investment model is often referred to as 5.1.h by Turkish stakeholders.[10] According to Article 5.1.h of the Unlicensed Electricity Generation Regulation, a generation facility based on renewable energy resources may be established at the same or different measurement point as the consumption facility. Previously, this was not possible, and a generation plant had to be installed in the same distribution region where the electricity was consumed. But in Türkiye, especially in some distribution regions where consumption is high, solar potential is low compared to other regions, and sites for land-type PV are costly. This regulation, especially within the scope of 5.1.h, enables large consumers to install new unlicensed power plants without the requirement of being located in the same distribution region as where the facility is established.[11] For example, a facility in the west part of the country is now entitled to meet its consumption from its distributed generation facility which is located in a region in the east. However, if these installations are made in distribution networks with low consumption, it may cause overloading in the networks due to high generation, bringing a challenge for future periods.

Also, more renewable energy capacity additions are expected to be installed using different investment models, in line with the Paris Agreement[12] and the Carbon Border Adjustment Mechanism. Since some of these new power plants will be connected via the distribution grids, this is one of the most important issues in designing a distribution grid.

1.4 Development of electric vehicles in Türkiye

Another significant concern within Türkiye pertains to the accelerating trend in EVs that have been gradually gaining attention, reflecting broader global trends towards sustainable and environmentally friendly transportation. Türkiye is emerging as one of the countries rapidly advancing in the adoption of EVs. While only 3.4% of the vehicles registered in 2020 were electric and hybrid vehicles, by 2023, the figures had surged, with hybrid vehicles accounting for 9.1% and EVs making up 5.9% of registered vehicles.[13]

1.5 Motivation and project content

The confluence of accelerating trends in electric mobility and distributed energy generation necessitates a forward-looking analysis of how Türkiye's electric distribution landscape must adapt to ensure a reliable, resilient and sustainable energy future.

The integration of various innovative smart grid solutions, such as the use of advanced network assets, grid-oriented control, storage systems, curtailment

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[9] Renewable Energy Sources Support Mechanism (YEKDEM in Turkish). For more details, please refer to the Annex.
[10] (Resmi Gazete, 2019)
[11] (Resmi Gazete, 2022)
[12] After the Paris Agreement was passed by the parliament in 2021, Türkiye had set a 41% emission reduction target over the Business-as-Usual Scenario in its INDC declared to the UNFCCC.
[13] (Türkiye İstatistik Kurumu, 2023)

strategies, voltage control, adaptation of technical guidelines, anticipatory grid planning and reduction of electricity demand, plays a crucial role in modernising and optimising distribution grid operations. Each of these options offers unique benefits and challenges, contributing to the overall stability and efficiency of the grid.

This project is centred on the examination of challenges and opportunities presented by the integration of EVs, DG and changing load dynamics within distribution systems, addressing transformative shifts in energy systems. In this study, we focus specifically on grid-oriented control measures. This choice is driven by the aim to isolate and examine the impacts of e-mobility on the distribution grid without the additional complexities introduced by storage systems. While storage systems are recognised for their potential to mitigate peak loads and support grid stability, their operation intersects significantly with broader market design considerations. By concentrating on measures that fall strictly within the purview of distribution grid operators, we can provide clear, actionable insights into grid management strategies that are directly implementable.

Real-world data for 2023 and projected data for 2030 and 2038 are utilised for analyses within this study.

- An optimised model for analysing medium-voltage (MV) distribution system operations is created, considering EVs, DG and load dynamics. Insights gained will be used to inform grid condition and capacity planning.
- Comprehensive input data, including distribution system operation areas, EV demand and DG production data, are compiled. Consideration is given to 2030 and 2038 scenarios, projecting changes in loads, EV adoption and DG integration.
- The impact of EV charging stations and DG units on power losses, voltage profiles and load flows is evaluated. The role of DG in mitigating voltage drops and reducing line losses caused by EV loads is analysed. Furthermore, transformer, feeder overloading and topology conditions are comparatively discussed. System performance implications with expanded network configurations are assessed.

The remainder of the report is organised as follows: Section 2 includes real data-based analysis results. Section 3 presents the concluding remarks as well as the detailed recommendations for action.

2 Real test system results

2.1 Real data source

The data gathered from one of the largest distribution system operators (DSOs) in Türkiye have been used to assess the impacts of new integrated systems such as EVs and DG on distribution system operation. The distribution system operation-oriented analyses are conducted using a mixed-integer quadratically constrained programming (MIQCP) based optimisation model depicted by the sample flowchart shown in Figure 3. The details of the model are given in the Annex.

2.2 2023 case analysis for the real test system

The real system to be considered in Türkiye was chosen in order to represent an area with a substantial load growth potential and a more city-centric concept. Therefore, the mentioned centric area includes a higher EV load capacity compared to DG penetration. Moreover, as HP loads are rarely used in Türkiye and are not considered as widely applicable in the foreseeable future, they are not considered in the real cases hereinafter in order to ensure a realistic analysis.

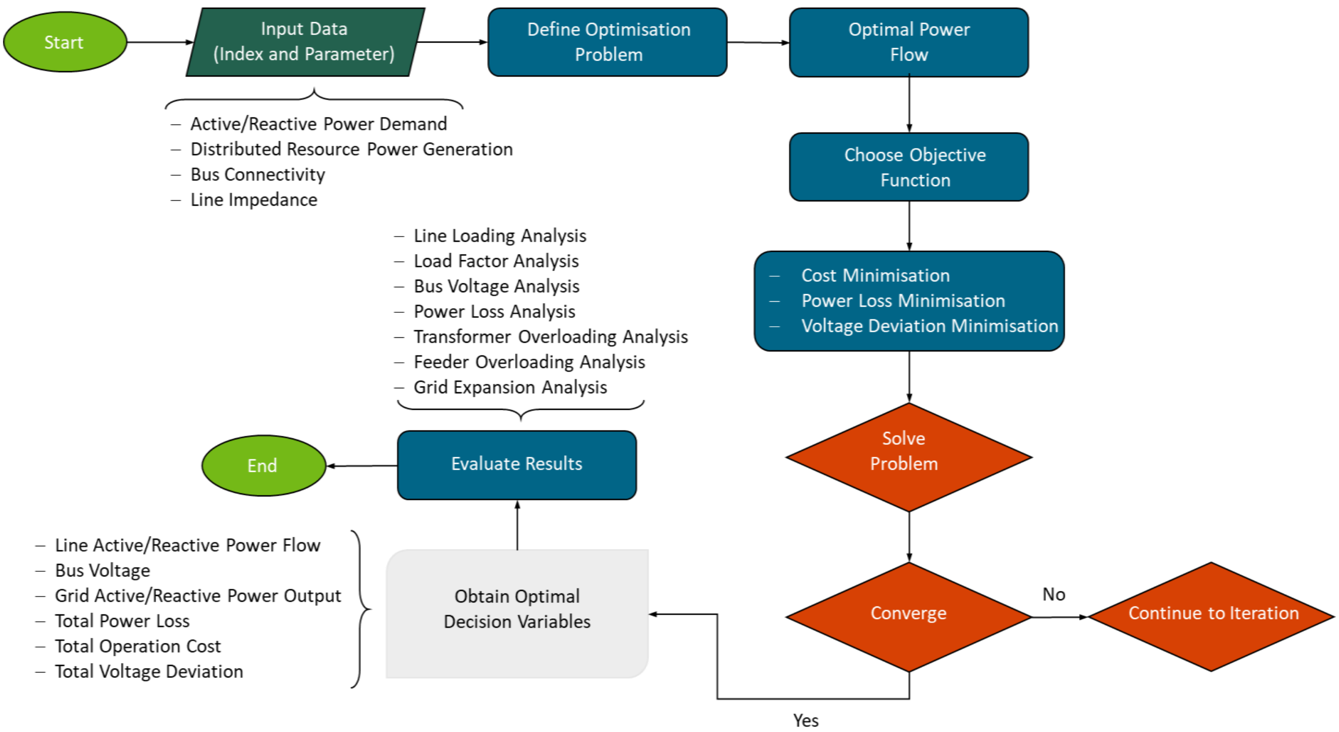

Figure 3. Flowchart illustrating the employed methodology

In order to depict the capabilities of the proposed methodology in a relatively smaller test system, firstly a synthetic data-based analysis was conducted on a sample system with more balanced EV and DG penetration along the buses, representing a rural case rather than crowded city-centric areas. The mentioned preliminary sample test system results are provided in the Annex. Then, the existing real test system data for the 2023 case and expected real test system structure for the 2030 and 2038 cases are analysed, resulting in the discussions given in the next subsections:

The goal of this section is to investigate the impact of EVs with low, medium and high-level charging scheduling and high-capacity DG on the line loading, load factor and bus voltages within the 1536-Bus real test system.

The data for this case study were provided by one of the largest DSOs in Türkiye. Additionally, total power losses are addressed and evaluated for various scenario simulations. In order to evaluate the effects of both EV and DG on the distribution system, three different case studies are carried out as follows:

- Base Case: Operation of the distribution system without DG and EV charging infrastructure
- Case-1: Operation of the distribution system containing EV charging stations
- Case-2: Operation of the distribution system containing DG and EV charging stations.

Figure 4 depicts the network topology of a real distribution system with the 1536-Bus in a region of Türkiye that is used for test studies. There are 91 EV AC/DC charging stations with varying power levels and 136 PV-based DG in this region.

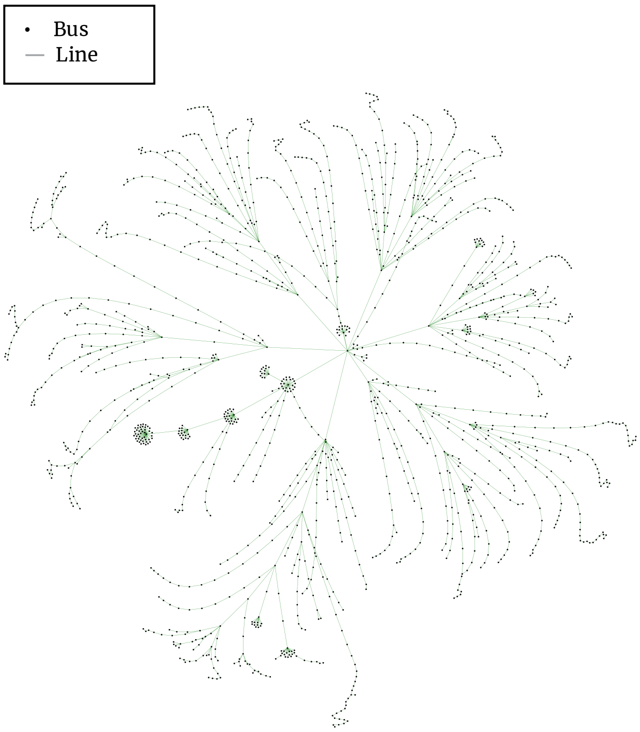

Figure 4. Network topology of the 1536-Bus real distribution system provided by the distribution system operator in Türkiye for a 2023 case[14]

In order to investigate the effects of DG and EVs on the distribution system, five buses are selected for this report. There are five different buses that include different types of EV charging stations and DG: one with a 7.4-kW AC charger, another with a 22-kW AC EV charger, one with a combined DC charging capacity of 600 kW, one with a 240-kW photovoltaic power (PVP) and one with a 920-kW PVP.

The results are explained with graphs, and, in particular, substations with EV charging station capacities at different power levels are preferred. The impact of the increase in installed charging station power on voltage, line losses and load flows between substations is detailed.

Additionally, the discussion revolves around how the installed capacity of DG units in a substation affects voltage drops and line flows due to EVs. The aim is to have the DSO fully handle both the integration of EVs and the installation of DG units, based on these findings. The potential outcomes of the increase in vehicle integration into the grid and the expansion of the production capacity of DG units are thoroughly discussed, paving the way for the operator to make more informed investment plans.

General conclusion for the 2023 case

Based on the 2023 case analysis of the real test system in Türkiye, several key insights can be derived regarding the impact of EV integration and DG units on the distribution system. The study reveals the following:

- EV and DG Integration Impact: The integration of EVs and DG units, such as PV systems, into the distribution system is feasible and leads to quantifiable changes in line loading, voltage profiles and power losses.

- Line Loading and Voltage Changes: The study shows that the addition of EV charging stations and DG units moderately alters line loading and voltage profiles. These changes are more noticeable with higher levels of EV charging power but remain within acceptable operational limits.

- Reduced Power Losses with DG: A significant finding is that the integration of DG units, especially those with higher capacities, tends to decrease total power losses in the system. This suggests that DG can enhance grid efficiency by reducing reliance on the central power supply and minimising distribution losses.

- Grid Stability in 2023: Overall, the study indicates that the grid in 2023 can accommodate the additional loads and generation sources from EVs and DG without major problems. This reflects a positive outlook for the grid's ability to adapt to new technologies and demands.

In summary, the 2023 case study provides evidence that the integration of EVs and DG has manageable impacts on grid operation in the current status of the analysed real area with the current penetration rates.

Line loading analysis

In Figure 5, the loading profiles on the line to which the low-level EV charging power is connected are depicted for each case study. In Case-1, the optimal charging scheduling through a 7.4-kW AC charging unit results in

[14] This network topology does not accurately represent the physical location and length of the lines. The graph program Gephi 0.10 is used to determine the locations of buses.

a slight increase in line loading compared to the Base Case. In Case-2, the power flowing through the line remains constant since there is no DG connection at both the EV bus and any bus on the same radial feeder. The maximum loading of 5.22 MVA on the line with a capacity of 44.51 MVA occurs at 9 PM in all case studies, and the maximum loading rate in the Base Case is 11.72%, while it is calculated as 11.74% in both Case-1 and Case-2.

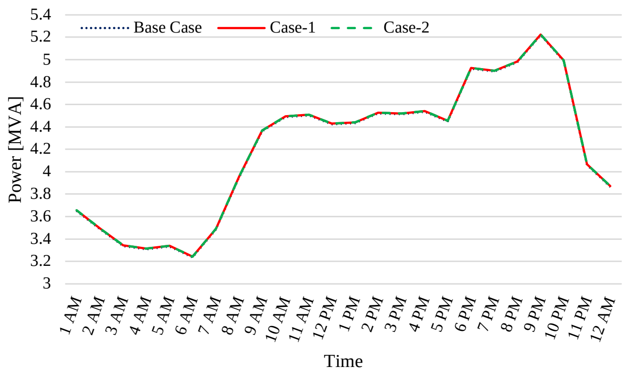

Figure 5. Loading profiles of the line connected to the low-level AC charger bus

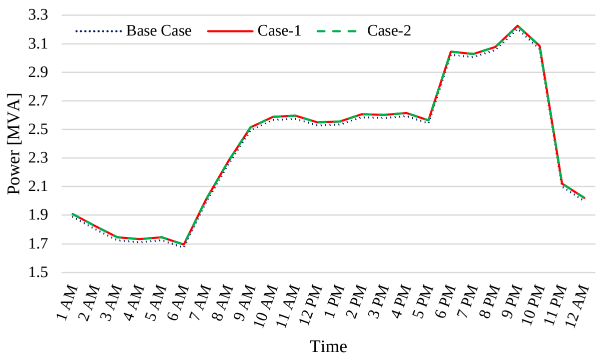

Figure 6. Loading profiles of the line connected to the medium-level AC charger bus

The loading profile on the line to which the medium-level EV charging power is connected, with charging planning conducted through a 22-kW AC charging unit, is illustrated in Figure 6 for each scenario study. In comparison to the low-level EV charging scenario, the line loading in Case-1 shows a slightly higher increase than the Base Case, although the increment rates still remain very low. Similarly, the power flowing through the line remains constant in Case-2 due to the absence of DG connections in proximity to the medium-level EV bus. The maximum loading on the line with a capacity of 35.09 MVA occurs at 9 PM for all case studies. While the maximum loading rate in the Base Case is 9.13%, it is computed as 9.19% in both Case-1 and Case-2.

The impact of high-level EV charging power planned through a 600-kW DC fast charging unit is examined in Figure 7 for each case. Apart from the analyses for the low and medium-level EV charging, both loadings in the line in Case-1 and Case-2 increase notably compared to the Base Case. Apart from the region where low and medium-level EVs are situated, there is a low-capacity DG with an installed power of 13.2 kW on the feeder where the high-level EV bus is located. This marginally alleviates the load on the line compared to Case-1 as the demands are met locally. The maximum loading on the line with a capacity of 36.64 MVA occurs at 9 PM in all case studies. The maximum loading rate is 8.02% in the Base Case, whereas it is calculated as 10.15% in both Case-1 and Case-2.

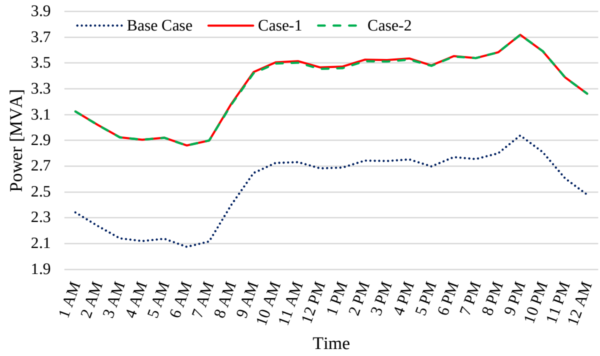

Figure 7. Loading profiles of the line connected to the high-level DC charger bus

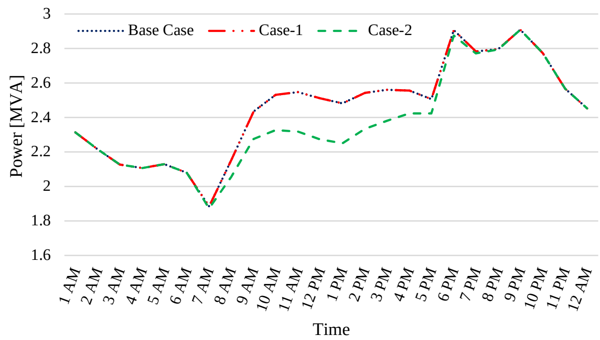

Figure 8. Loading profiles of the line connected to the 240-kW DG bus

Lastly, the effects of two sets of DG with power capacities of 240 kW and 920 kW are evaluated in Figure 8 and Figure 9 respectively, considering various loading profiles on the demand side. The power flow in the lines does not change much since the charging powers of EVs are low in the Base Case and Case-1 for both scenarios. However, there is a substantial reduction in the power drawn from the main grid in Case-2, where DG supplies power regionally, resulting in a reduction of power flow through the lines.

A more significant reduction in net power at midday, with the 920-kW high-capacity DG, is observed in Case-2, as expected when comparing the two scenarios. In addition to that, it is worth mentioning that no change in the loading rates is observed since the peak load occurs at time intervals with no DG generation. At 12 PM, one of the peak DG generation intervals is managed, and the maximum loading reaches 7.94% with 240 kW of DG.

Conversely, it is recorded at 7.53% when there is 920 kW of DG present.

However, the minimum net power demand at noon in the case of high-capacity DG requires a higher generator ramp-up rate to meet the expected demand in the subsequent time intervals, and this shows that network planning must be done very carefully.

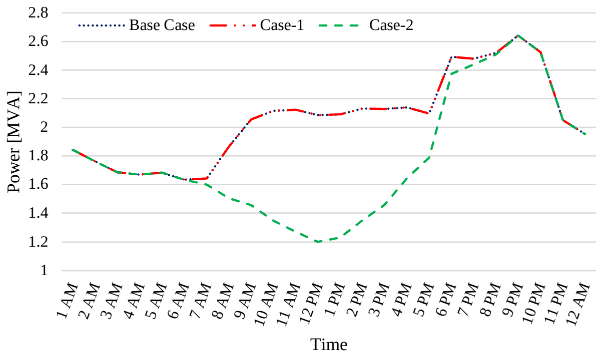

Figure 9. Loading profiles of the line connected to the 920-kW DG bus

Load factor analysis

The load factor (LF) is a metric that indicates the efficient utilisation of the power system. Here, the term 'load factor' in electrical power systems is a ratio indicating steadiness in electricity usage. A low load factor indicates greater peak power variability, characterised by power fluctuations. The load factor is defined as the average load (total energy consumption divided by time, in kilowatts) over the peak load (maximum power demand, in kilowatts) in a given period, expressed using the following equation:

$$LF = \frac{Average\ Demand}{Maximum\ Demand}$$

The load factor ranges from 0 to 1 (0% to 100%), with a high load factor meaning more consistent electricity use. For instance, when it is assumed that the average demand of a building or a region is 8 MVA, and the maximum demand is 10 MVA, the load factor is calculated as 0.8 or 80%. The load factor represents the resource utilisation in power generation and distribution and is directly related to the costs.

Table 1 shows the results of the load factor analysis for three different EV charging levels and locations. Here, it is worth noting that the results are evaluated by column[15]. For each level, we analyse the rise of the LF in Case-1 and Case-2 compared to the Base Case.

Similar to the line loading analysis, the impact in Case-1 is significantly minimal compared to the Base Case. On the other hand, the 600-kW DC fast charging planning (high level) raises the load factor by 2.81 percentage points, as it increases the daily average power amount more than the maximum peak power. However, the load factor ratios in Case-2 remain constant or are influenced very slightly due to the relatively low impact of the selected DG power on the EV buses.

Load Factor (%)	Low Level EV Charge	Medium Level EV Charge	High Level EV Charge
Base Case	80.59	74.41	86.72
Case-1	80.62	74.58	89.52
Case-2	80.62	74.58	89.41

Table 1. Load factor of charger-connected buses

The medium-level EV charge consistently results in a similar load factor (around 74%) because the bus it is connected to has stable characteristics across all cases. The impacts of 240-kW low capacity and 920-kW high-capacity DG on the load factor can be seen in **Table 2**. As the EV effect on the buses planned for DG integration is similarly low, the load factor does not exhibit significant changes in Case-1. Additionally, a decrease in the load factor is observed as a result of DG integrations in Case-2. The main reason behind this is the decrease in the average power drawn from the grid while maintaining the same maximum peak power. Consequently, it is concluded that the increase in PV-based DG power leads to a reduction in the load factor. Furthermore, the impact of the increased DG power resulting in a lower load factor is clearly seen from the table. The load factor is decreased by 2.601 percentage points and calculated as 81.7% with the 240-kW DG connection. On the other hand, it is observed that the load factor of the bus is 67.23% in the case of a 920-kW high-capacity DG connection, indicating a decrease rate of 10.69 percentage points. Similar to the line loading analysis, this underscores the need for coordinated operation of DG integrations with grid equipment such as energy storage systems.

[15] The LF results are evaluated by column. The impact of all EV levels is analysed separately since the connection bus of each one is different. The specific buses to which these EV charging levels are connected have different characteristics (like their maximum power demand and average power consumption), which directly influence the load factor. More information on the analysis of the individual LFs may be found in the Annex.

Load Factor (%)	240-kW DG	920-kW DG
Base Case	84.30	77.92
Case-1	84.30	77.92
Case-2	81.70	67.23

Table 2. Load factor of DG-connected buses

Voltage analysis

The voltage profile of a bus with a 7.4-kW AC EV charging station for the three cases is shown in Figure 10. In the Base Case, the drop in voltage peaks at 9 PM as a result of the increased demand during the day. The voltage decrease is less noticeable at night. There is no apparent change in the voltage profile between the Base Case, Case-1 and Case-2. It has been noted that the voltage profile is unaffected by the 7.4-kW AC EV charging station and DG. This bus's daily average load demand is 530 kVA. As a result, EVs and DG have relatively little impact. During the day, the Base Case shows a total voltage drop of 0.332 p.u., but Case-1 and Case-2 show a total voltage drop of 0.333 p.u. The voltage in the bus under examination lowers to 1.010 p.u., the minimum value.

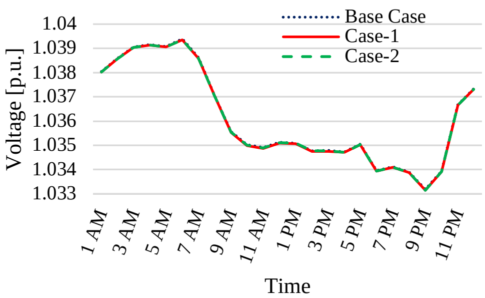

Figure 10. Voltage profiles of the bus connected to the low-level AC charger

The voltage profile of a bus with a 22-kW AC EV charging station is displayed for three cases in Figure 11. Due to the increased load demand during the day in the Base Case, there are more voltage drops during the day than at night. The voltage profile in Cases 1 and 2 is the same as it was in the Base Case. It has been noted that the voltage profile is not visibly affected by EVs or DG. It is evident that there is no adverse effect from the 22-kW EV charging station at the bus, which has an average daily load demand of 445 kVA. In the Base Case, there is a voltage decrease of 0.786 p.u. during the day. The voltage drop is 0.787 p.u. and 0.787 p.u. in Cases 1 and 2, respectively. When the charging station is incorporated into the distribution system, the voltage drop increases. However, when the DG is activated in Case-1, the voltage drop falls.

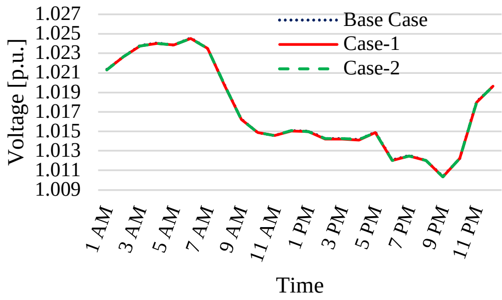

Figure 11. Voltage profiles of the bus connected to the medium-level AC charger

Voltage profiles for three case studies of a bus with a 600-kW DC charging station are shown in Figure 12. As a result of the increased power demand in the Base Case, there is a higher voltage drop during the day than at night. In the evening, the voltage decreases to 1.031 p.u. Case-1 examines the notable alterations in the bus's voltage profile upon activation of the EV charging station. The bus's average daily non-EV power demand is 190 kVA. In Cases 1 and 2, there is a higher voltage drop than in the Base Case. The total daily voltage drop in the Base Case is 0.373 p.u. In Cases 1 and 2, there is a total voltage drop of 0.387 p.u. and 0.385 p.u., respectively. In comparison to Case-1, it is observed that the voltage drop is lower when the PV plant is activated during the day. It has been noted that DG can lessen the detrimental impact that EVs have on the voltage profile.

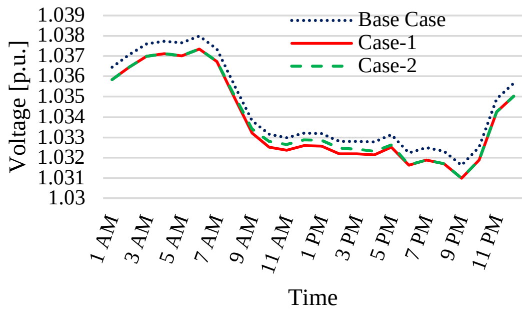

Figure 12. Voltage profiles of the bus connected to the high-level DC charger

The voltage profile of a bus with a 240-kW PV plant is shown for all three cases in Figure 13. It is noted that the Base Case exhibits a greater voltage drop during the day than at night. The lowest voltage level in the Base Case is 1.042 p.u., and the overall voltage drop is 0.144 p.u. The addition of EVs in Case-1 does not significantly alter the voltage profile, although there is a total voltage drop of 0.145 p.u. at the level. In Case-2, an increase in the bus's voltage profile is noted upon the activation of DG. The bus's average daily demand is 286 kVA. It is observed that during the day, when the sun is shining, the voltage drops. In comparison to the Base Case and Case-1, the overall voltage drop is reduced and reaches 0.143 p.u. in Case-2.

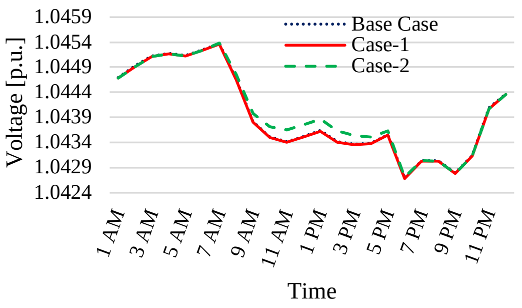

Figure 13. Voltage profiles of the bus connected to the 240-kW DG

The voltage profile of a bus with 920-kW PV for three cases appears in Figure 14. In the Base Case, the lowest voltage level is 1.044 p.u., and the overall voltage drop during the day is 0.107 p.u. When the EV charging stations are activated in the distribution system, Case-1 shows no change in the voltage profile or overall voltage drop. When the 920-kW PV in Case-2 is powered on, the voltage profile in this bus, which has a daily average demand power of 66 kVA, alters. When PV generation is operating, there is a reduction in voltage drop. The total voltage drop is measured at 0.105 p.u. It is observed that DG has a positive effect on the voltage profile.

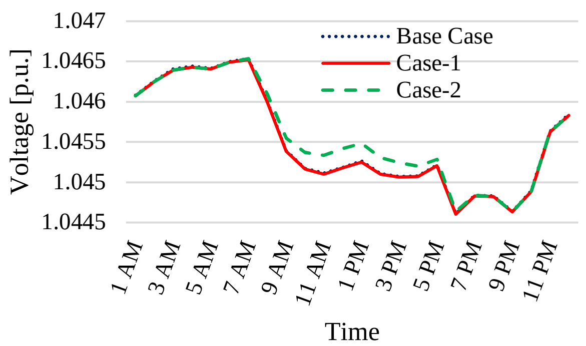

Figure 14. Voltage profiles of the bus connected to the 920-kW DG

Power losses analysis

Table 3 presents the total grid losses for each case study analysis. The total active energy loss is 168.93 MWh, and the total reactive energy loss is 103.83 MVArh in the Base Case, where EV and DG integration are not considered. Additionally, the losses rise to 172.236 MWh and 105.760 MVArh in Case-1 due to the increase in demand resulting from EV integrations. Finally, the power drawn from the grid is decreased in Case-2 as the loads are regionally supplied along with the integration of DG. As a result, the active and the reactive energy losses are reduced to 171.17 MWh and 105.11 MVArh, respectively, due to the decrease in power flows through the distribution lines.

	Active Losses [MWh]	Reactive Losses [MVArh]
Base Case	168.93	103.83
Case-1	172.23	105.76
Case-2	171.17	105.11

Table 3. Total grid losses for each case

2.3 2030 case analysis for the projected test system

This section analyses the effects of increasing demand for EVs and DG capacity on the distribution system, incorporating the projections of the DSO for 2030. Figure 15 illustrates the anticipated topology of the distribution system in 2030.

Figure 15. Projected network topology of the 2152-Bus distribution system provided by the distribution system operator in Türkiye for the 2030 case[16]

As compared to 2023, 616 additional buses are projected to be added to the system in 2030 considering the

[16] This network topology does not accurately represent the physical location and length of the lines. The graph program Gephi 0.10 is used to determine the locations of buses.

distribution system growth plan of the real DSO. The distribution system will include 2054 EV charging stations and 178 DG units in 2030. The comparison of 2030 and 2038 cases with the 2023 case in terms of expected EV and DG capacity increase is depicted in Table 4.

Case	# of buses	EV capacity [MW]	DG capacity [MW]
2023	1536	5.2	8.8
2030	2152	408.4	10.2
2038	2550	1681.7	17.8

Table 4. Changing EV and DG capacities for 2023, 2030 and 2038 scenarios

As can be seen, the demand is gradually increasing while EV capacity is expected to increase significantly more than DG penetration, which is expected to increase relatively slowly considering the fact that the analysed physical area is city centric.

The study area is a developing urban region. It is characterised by a very high growth of EV charging stations and a very limited potential for DG installations. The available space for DG installations is limited to rooftops in the area. Therefore, the increase in EV charging stations far exceeds the increase in DG installations.

It should be noted here that the 2030 and 2038 cases are based on a worst-case analysis rather than applying a time-varying profile for load and generation. This is mainly based on the fact that it is not possible for the DSO to create time-varying realistic profiles for such mid- and long-term periods.

General conclusion for the 2030 case

Based on the 2030 case analysis for the projected test system, the following key conclusions can be drawn:

- Increased demand and system expansion: The distribution system is expected to experience significant growth by 2030, with a substantial increase in the number of buses, EV charging stations and DG units. This reflects the growing demand for electricity and the rapid adoption of EVs.
- Line loading and voltage profile changes: The study indicates that the integration of a higher number of EVs and DG units will lead to notable changes in line loading and voltage profiles. The system shows increased power flow and voltage drops in scenarios with high EV loads, and the impact of DG units in mitigating these effects is limited.
- Power losses escalation and mitigation: With the expansion of the network and increased demand from EV integrations, both active and reactive power losses are expected to rise. However, the integration of DG units helps in reducing these losses slightly, demonstrating their role in improving system efficiency.
- Transformer overloading concerns: A significant issue identified is the potential overloading of transformers, especially when considering the additional EV load. The study indicates that a substantial portion of transformers may reach or exceed 80% of their capacity, signalling a need for infrastructure and topology enhancement or better load management strategies.

In summary, the main challenges identified for 2030 are managing increased demand, mitigating transformer and feeder overloading, and balancing line loading and voltage profiles in the face of significant EV and DG integration. While DG units provide some relief, their impact is relatively modest compared to the scale of the changes.

Line loading analysis

In Figure 16, the power flow from the slack bus up to the bus without DG but containing 739.69 kW of EV power is illustrated. Here, Bus-150 represents the slack bus, while Bus-1215 represents the previously mentioned bus. In the Base Case, the power supplied from the slack bus to the relevant feeder is 207.39 MVA, and after meeting the demands at the buses on the feeder, the power reaching Bus-1215 is 4.84 MVA. In Case-1, considering the presence of EVs, the power leaving the slack bus is 282.86 MVA, and the power reaching Bus-1215 is 7.06 MVA. In this context, the total load on the relevant bus has increased by 45.81%. In Case-2, considering the impact of DG, the power transferred to the selected feeder from the slack bus has decreased by 2.48 MVA to 280.38 MVA. However, the additional DG contribution from other feeders has still been utilised by different buses and consumed up to Bus-1215. Therefore, the power reaching Bus-1215 remains constant at 7.06 MVA.

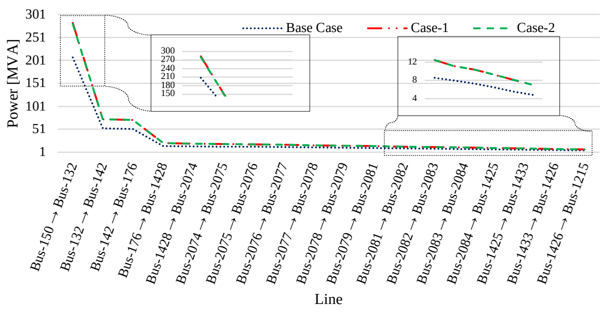

Figure 16. Feeder load flow from slack Bus-150 to EV Bus-1215

In Figure 17, a similar power flow is illustrated from the slack bus to Bus-935, containing 1279.69 kW of EV power but without DG. Unlike the previous scenario, the DG power generated in other feeders is also consumed at the selected bus of the chosen feeder. Specifically, in the Base Case, the power supplied from the slack bus to the relevant feeder is 162.52 MVA. After meeting the demands at the buses on the feeder, the power reaching Bus-935 is 8.2 MVA. In Case-1, with 220.11 MVA leaving the slack bus, the power reaching Bus-935 is 10.41 MVA, influenced by EV loads on the feeder. In Case-2, despite the high-power EV loads, the DG power generated in neighbouring feeders is also consumed at the buses of the selected feeder. In this case, the power supplied from the slack bus to the relevant feeder is 217.84 MVA, and the power reaching Bus-935 is reduced to 9.36 MVA.

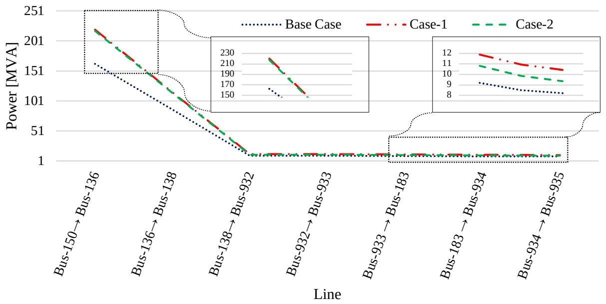

Figure 17. Feeder load flow from the slack Bus-150 to the EV Bus-935

In Figure 18, the power flow from the slack bus up to Bus-2085, containing 247.79 kW of EV power and 320 kW of DG, is depicted. In comparison to the analysis of Bus-935, the power supplied from the slack to the relevant feeder has similarly decreased due to DG in neighbouring feeders. However, the impact of neighbouring DG power has diminished up to Bus-2085. On the other hand, with the aid of DG production at Bus-2085, the amount flowing through the last line was slightly lower. In the Base Case, the power supplied from the slack bus is 207.39 MVA, and the power reaching Bus-2085 is 10.61 MVA. In Scenario-1 and Scenario-2, with the power supplied from the slack to the feeder being 282.86 MVA and 280.37 MVA, respectively, the power reaching Bus-2085 is 13.98 MVA and 13.22 MVA, respectively.

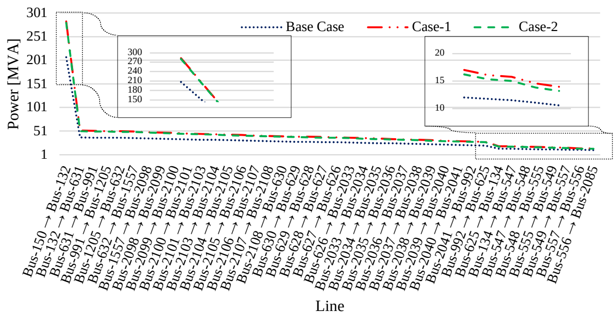

Figure 18. Feeder load flow from slack Bus-150 to EV+DG Bus-2085

Figure 19 depicts the power flow from the slack bus up to Bus-425, containing 100.64 kW of EV power and 999 kW of DG power. In contrast to other analyses, the EV load was alleviated due to the high DG power. In the Base Case, the power supplied from the slack bus is 162.52 MVA, and the power reaching Bus-425 is 3.39 MVA. In Case-1 and Case-2, with the power supplied from the slack to the feeder being 220.11 MVA and 217.84 MVA, respectively, the power reaching Bus-425 is 4.46 MVA and 3.42 MVA, respectively. Clearly, in Case-2, with the high DG power production, the power flowing through the line connected to the relevant bus was low, almost around the base case load.

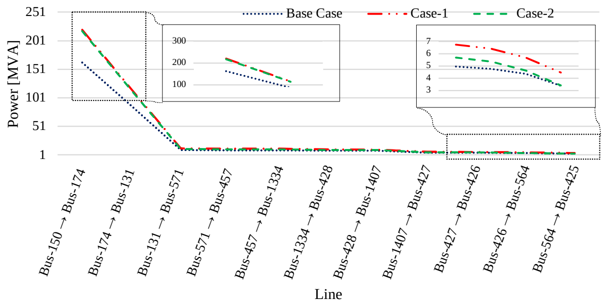

Figure 19. Feeder load flow from slack Bus-150 to EV+DG Bus-425

Voltage analysis

The voltage drop observed in all case studies of the line to which a 740-kW total-power EV charging station bus is connected is depicted in Figure 20. The voltage is observed to decrease from 1.05 p.u. to 0.999 p.u. in the Base Case. The calculated voltage drop is 0.051 p.u. In Case-1, the voltage drop is exacerbated by EV loads. Voltage decreases to 0.982 p.u. from 1.05 p.u. The calculated voltage drop is 0.068 p.u. The voltage profile does not vary noticeably in Case-2, when the DG is activated due to the lower power rating of DG units compared to EV loads.

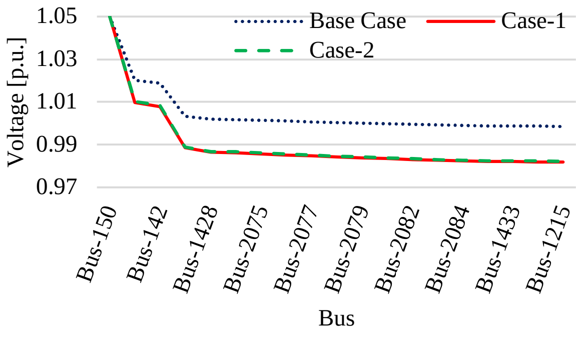

Figure 20. Voltage profile of the line from slack Bus-150 to EV Bus-1215

The voltage profile of the line to which a bus containing a 1280-kW EV charging station is connected is depicted in Figure 21. The voltage decreases from 1.05 p.u. to 1.025 p.u. in the Base Case. An overall decrease in voltage of 0.025 p.u. is detected. A change is observed in the voltage profile of Case-1 when EV loads are introduced. Voltage decreases by 1.017 p.u. from 1.05 p.u. An overall voltage drop of 0.033 p.u. is detected. It is evident from Case-2 that the addition of DG to the system has no apparent effect on the voltage profile.

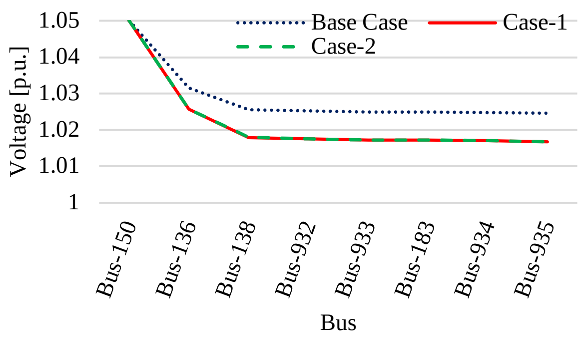

Figure 21. Voltage profile of the line from slack Bus-150 to EV Bus-935

The voltage variation of the line to which a bus is connected with 320-kW DG capacity and a 250-kW EV charging station is depicted in Figure 22. The voltage decreases from 1.05 p.u. to 0.981 p.u. in the Base Case. The total voltage drop amounts to 0.069 p.u. When EV loads are introduced into Case-1, the voltage decreases from 1.05 p.u. to 0.957 p.u. The calculated total voltage drop is 0.093 p.u. Case-2 reveals that the implementation of DG does not result in a substantial alteration to the voltage profile. The voltage decreases to 0.959 p.u. from 1.05 p.u. The calculated total voltage drop is 0.091 p.u., which is less than Case-1.

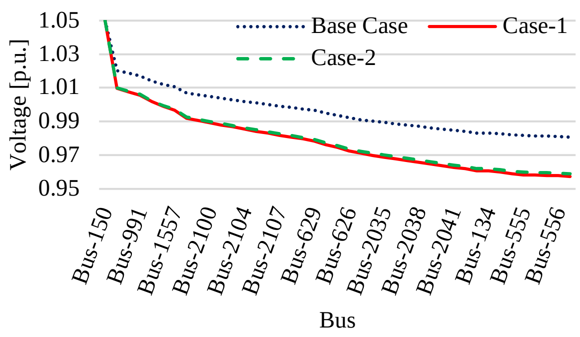

Figure 22. Voltage profile of the line from slack Bus-150 to EV+DG Bus-2085

Figure 23 illustrates the voltage variation of a line that is connected to a bus containing an EV charging station with a total power of 100 kW and a DG capacity of 999 kW. The voltage of this bus decreases from 1.05 p.u. to 1.012 p.u. in the Base Case. Along the line, the voltage drop is 0.038 p.u. The introduction of EV loads results in an increase in voltage drop in Case-1. The voltage of the bus decreases from 1.05 p.u. to 1.001 p.u. The calculated total voltage drop is 0.049 p.u. Case-2 demonstrates that the activation of DG does not induce any noticeable change in the voltage profile. Voltage decreases from 1.05 p.u. to 1.001 p.u. DG has been found to be inadequate in mitigating the adverse effects of EV loads.

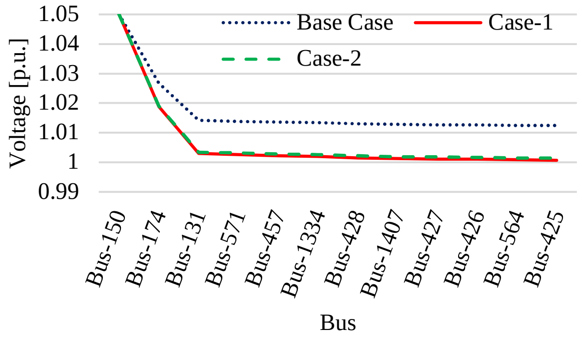

Figure 23. Voltage profile of the line from slack Bus-150 to EV+DG Bus-425

Power losses analysis

Table 5 presents the total grid losses for each case study analysis. The total active energy loss of the entire network is 30.14 MWh, and the total reactive energy loss is 21.56 MVArh in the Base Case, where EV and DG integration are not considered. Additionally, the losses rise to 54.93 MWh and 39.15 MVArh in Case-1 as expected, due to network expansion and the increase in demand resulting from EV integration. Finally, the active and the reactive energy losses are reduced to 54.17 MWh and 38.61 MVArh, respectively, due to the decrease in power flows through the distribution lines.

	Active Losses [MWh]	Reactive Losses [MVArh]
Base Case	30.14	21.56
Case-1	54.93	39.15
Case-2	54.17	38.61

Table 5. Total grid losses for each case

Transformer overloading analysis

As a distinctive concept for the scenarios in 2030 and 2038, this study comparatively analyses the overloading conditions of the existing transformers. It is important to note that a transformer is considered overloaded when its loading exceeds 80% of its capacity. While this 80% threshold might not be entirely relevant for countries with mature infrastructures that offer higher reliability levels, it holds significant practical importance for rapidly developing countries like Türkiye. This threshold serves as an early warning indicator for these crucial pieces of equipment, signalling the potential for exceeding capacity within a very short timeframe.

In this context, the planning and implementation processes of investment projects are vital. These processes consist of interconnected subprocesses, including survey, design, expropriation-land allocation, project approvals, material supply and excavation permits, all of which are time-consuming. Recognising the importance of managing transformer loads effectively, an 80% transformer overloading ratio is adopted as a standard. This standard is not only a measure to meet potential instantaneous and permanent loads but also a proactive step to initiate the aforementioned planning processes in a timely manner. By adhering to this overloading ratio, it is possible to commence the planning and implementation phases before the transformers reach their full capacity, thereby ensuring the accommodation of any additional loads and maintaining the reliability and efficiency of the power infrastructure.

	Total number of transformers with load	Number of overloaded transformers (exceeding 80% of capacity)	Ratio of overloaded transformers (exceeding 80% of capacity) [%]
Base Case	2054	325	15.82
Case -1	2054	946	46.06
Case -2	2054	937	45.61

Table 6. Transformer overloading ratios for different cases.

As seen in Table 6, the regular load growth gives an 80% alert for slightly over 15% of the total transformers. However, when EV load is added, this level goes up to 46%, depicting the significant impact of EV load compared to normal load growth. Furthermore, the relatively low DG capacity positively affects this overloading condition, even though this is only a slight impact.

Feeder overloading analysis

In the context of the 2030 and 2038 scenarios, a thorough feeder overloading analysis has been conducted. It is established that a feeder including more than 20 transformers in a ring grid structure is considered overloaded due to various practical reasons. Operating a feeder with this number of transformers becomes impractical from the DSO perspective. Consequently, new feeder investments and planning actions are advisable for such overloaded areas.

This scenario directly connects to the realisation that the length of the feeder and the number of transformers connected to it have significant impacts on network stability. Excessive numbers of transformers, coupled with extended feeder lengths, contribute to an increase in fault points, which in turn prolongs the response time for potential failures. Such scenarios also lead to overloading beyond the feeder's capacity, provoke voltage drop issues, and result in heightened technical losses. Therefore, it is generally advised that limiting the maximum number of transformers on a feeder to 20 in a ring configuration is prudent. This limitation aids in maintaining loadings and distances at optimal levels, thereby ensuring a more operable and stable system.

Implementing these measures is vital for the efficient management of the network, especially in light of the increasing demands and complexities foreseen in future scenarios. The relevant feeder overloading analysis for the 2030 case is depicted in Table 7.

Total number of feeders	Number of feeders exceeding 20 transformers	Ratio of feeders exceeding 20 transformers [%]
225	26	11.55

Table 7. Feeder overloading data

2.4 2038 case analysis for the projected test system

This section examines the effects of EVs and DG on the distribution grid, with projections provided by the DSO for 2038. The projected increase in the number of buses between 2030 and 2038 is 398, for a total of 2550 buses. The topology of the 2550-Bus distribution system is illustrated in Figure 24. The distribution system is anticipated to contain 2443 EV charging stations and 222 DG units in 2038.

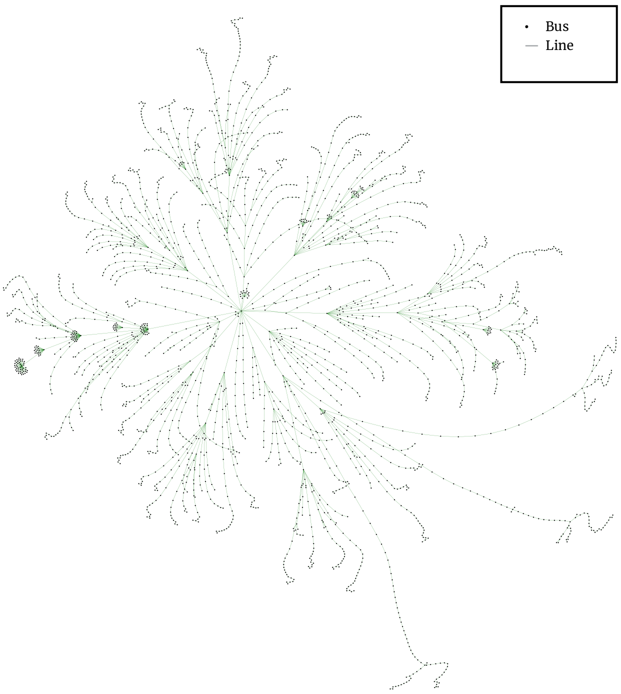

Figure 24. Projected network topology of 2550-Bus distribution system provided by distribution system operator in Türkiye for 2038 case

General conclusion for the 2038 case

The 2038 case analysis for the projected test system offers several key insights:

- Significant Growth in EV and DG Integration: By 2038, the distribution system is projected to experience considerable growth, with a substantial increase in EV charging stations and DG units. This growth indicates a continued trend towards electrification and renewable energy adoption.

- Increased Line Loading and Voltage Drops: The analysis shows that the integration of higher EV powers significantly increases line loading, leading to higher power flows and voltage drops. These changes are more pronounced in scenarios with higher EV loads, underscoring the need for robust grid infrastructure to handle these loads.

- DG's Role in Mitigating Impacts: Although DG units help in reducing the line loading and power losses, their impact is somewhat limited in offsetting the significant increases caused by EV integration. This suggests that while DG is beneficial, it alone may not be sufficient to counterbalance the extensive demands of EVs.

- Voltage Profiles Below Recommended Thresholds: In several cases, the voltage profiles fall below the recommended threshold of 0.9 p.u., especially in scenarios with high EV loads. This raises concerns about voltage stability and the need for improved voltage regulation strategies.

- Escalating Power Losses and Transformer Overloading: The analysis indicates a substantial increase in both active and reactive power losses, particularly in scenarios with high EV loads. Additionally, a significant portion of transformers are projected to operate above 80% of their capacity, suggesting potential overloading issues.

In summary, the 2038 case study underscores the challenges and complexities of managing a rapidly evolving power distribution system. It points to the urgent need for strategic planning and investment in grid infrastructure to ensure reliability and efficiency in the face of significant increases in EV adoption and renewable energy integration.

Line loading analysis

Figure 25 illustrates the power flow from the slack bus up to the bus without DG but containing 1942.26 kW of EV power. Here, Bus-216 represents the slack bus, while Bus-1005 represents the specified EV bus. In the Base Case, the power supplied from the slack bus to the relevant feeder is 162.82 MVA and after meeting the demands at the bars on the feeder, the power reaching Bus-1005 is 9.06 MVA. In Case-1, due to the high EV power, the power leaving the slack bus is 312.48 MVA, and the power reaching Bus-1005 is 17.36 MVA. In Case-2, despite considering the DG impact, the production in neighbouring feeders has almost no effect on the power transferred from the slack bus to the selected feeder. In this case, the power supplied from the slack bus to the relevant feeder is 312.37 MVA, and the power reaching Bus-1005 remains constant at 17.36 MVA.

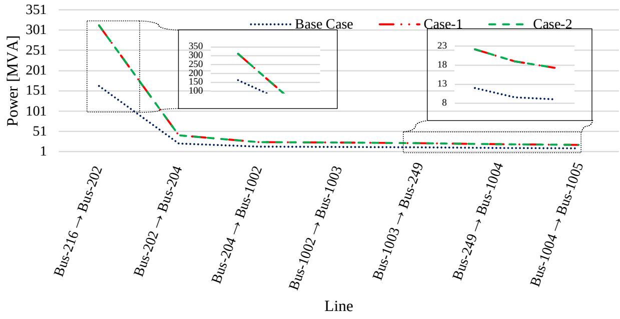

Figure 25. Feeder load flow from the slack Bus-216 to EV Bus-1005

Figure 26, Figure 27 and Figure 28 demonstrate power flows for different buses with variable EV powers and DG generations on the same feeder. Firstly, the power flow from the slack bus up to Bus-1228, containing 328.37 kW of EV power and 34 kW of low-capacity DG power, is shared in Figure 26. In the Base Case, the power supplied from the slack bus is 291.79 MVA, and the power reaching Bus-1228 is 0.11 MVA. In Case-1 and Case-2, with the power supplied from the slack to the feeder being 606.25 MVA and 601.37 MVA, respectively, the power reaching Bus-1228 is 0.43 MVA and 0.4 MVA, respectively. As can be seen, low EV power does not strain the line capacity, and low DG power similarly does not contribute significantly.

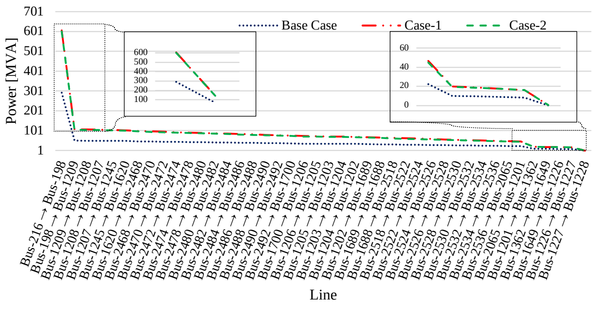

Figure 26. Feeder load flow from slack Bus-216 to EV+DG Bus-1228

On the other hand, the power flow from the slack bus up to Bus-2508, containing 867.43 kW of EV power and 390 kW of DG power with a capacity of 390 kW, is shared in Figure 27. Since the same feeder analysis is performed, the amounts of power supplied from the slack to the feeder are the same. The power reaching Bus-2508 is 7.01 MVA, 15.49 MVA and 14.32 MVA in the Base Case, Case-1 and Case-2, respectively. Unlike the previous scenario analysis, with the high DG power production, the additional EV load-induced line loading has been lowered by 1.18 MVA.

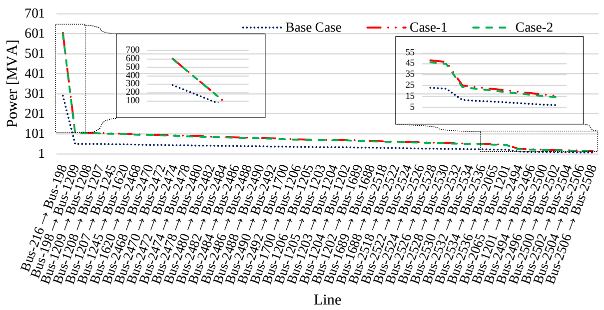

Figure 27. Feeder load flow from slack Bus-216 to EV+DG Bus-2508

Finally, the power flow from the slack bus up to Bus-2420, containing 867.43 kW of EV power and 570 kW of DG power with a capacity of 570 kW, is shown in Figure 28. In Bus-2420, in addition to Bus-2508, a more distant bus with the same EV power but higher DG power is integrated. The power reaching Bus-2420 is 13.10 MVA, 25.99 MVA and 24.41 MVA in the Base Case, Case-1 and Case-2, respectively. Furthermore, the loading on the line connected to the relevant bus has been reduced by 1.59 MVA.

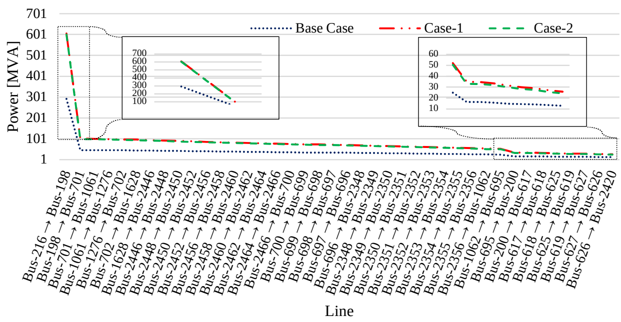

Figure 28. Feeder load flow from slack Bus-216 to EV+DG Bus-2420

Voltage analysis

Figure 29 illustrates the voltage variation of the line connected to a bus containing a 1942.26-kW EV charging station. The voltage decreases from 1.05 p.u. to 1.021 p.u. in the Base Case. The total voltage drop is determined to be 0.029 p.u. The introduction of EV loads in Case-1 causes the voltage drop to increase from 1.05 p.u. to 0.998 p.u. The total voltage drop amounts to 0.052 p.u. Activating the DG in Case-2 does not change the voltage drop or alter the voltage profile.

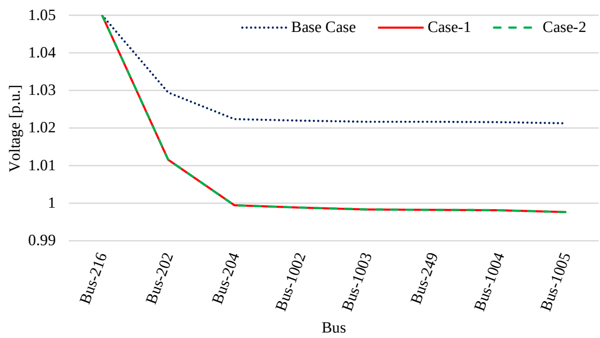

Figure 29. Voltage profile of the line from slack Bus-216 to EV Bus-1005

Figure 30 demonstrates the voltage profile of the line that is connected to a bus containing a 34-kW EV charging station and a DG unit, which has an installed power of 328.36. The voltage decreases from 1.05 p.u. to 0.963 p.u. in the Base Case, for an overall voltage drop of 0.087 p.u. Upon examination of Case-1, the voltage decreases from 1.05 p.u. to 0.877 p.u. The voltage drop is determined to be 0.173 p.u. in total. The voltage falls below the recommended threshold of 0.9 p.u. as a result of the increasing EV load. The voltage decreases from 1.05 p.u. to 0.879 p.u. in Case-2. The calculated total voltage drop is 0.171 p.u., which is less than Case-1. In this instance, however, the voltage falls below the recommended threshold.

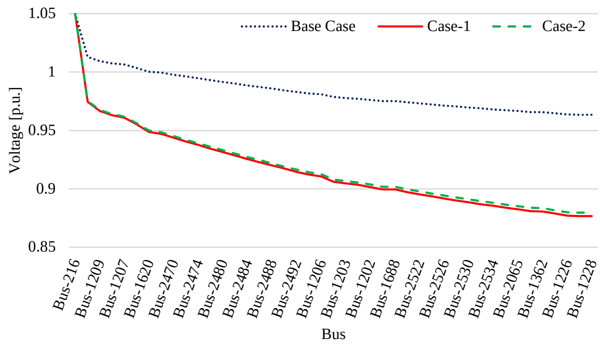

Figure 30. Voltage profile of the line from slack Bus-216 to EV+DG Bus-1228

The voltage variation of the line connected to a bus with a DG of 390 kW and an EV charging power station of 867 kW is depicted in Figure 31. The voltage decreases from 1.05 p.u. to 0.964 p.u. in the Base Case for a cumulative voltage drop of 0.086 p.u. The voltage in Case-1 decreases from 1.05 p.u. to 0.877 p.u. The voltage drop is determined to be 0.173 p.u. in total. The voltage drop in Case-2 is from 1.05 p.u. to 0.880 p.u. The voltage levels in Case-1 and Case-2 are both below the safe operating threshold of 0.9 p.u.

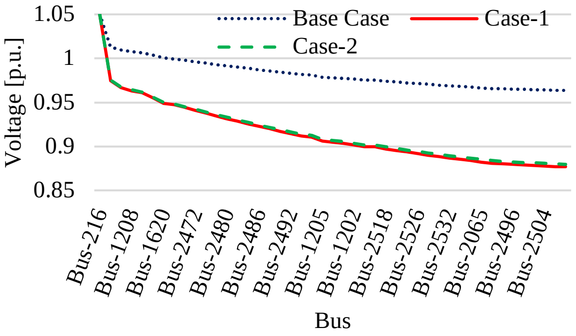

Figure 31. Voltage profile of the line from slack Bus-216 to EV+DG Bus-2508

Figure 32 illustrates the voltage variation that occurred along the line that connects a bus with 570 kW of DG and an 867.43-kW EV charging station. A voltage drop of 0.085 p.u. is observed in the Base Case, with the voltage dropping from 1.05 p.u. to 0.965 p.u. The voltage in Case-1 decreases from 1.05 p.u. to 0.879 p.u. The total voltage drop is determined to be 0.171 p.u. Case-2 does not exhibit any notable alterations in the voltage profile, with a voltage drop from 1.05 to 0.882 p.u. The voltage levels in Case-1 and Case-2 both decrease to levels below the safe threshold of 0.9 p.u.

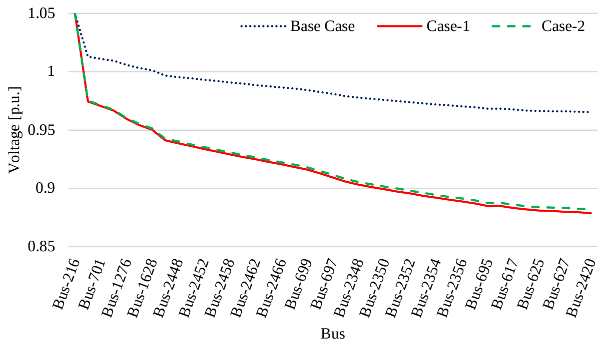

Figure 32. Voltage profile of the line from slack Bus-216 to EV+DG Bus-2420

Power losses analysis

The total grid losses for each case study are shared in Table 8. The total active energy loss of the entire network for the Base Case, Case-1 and Case-2 is 51.39 MWh, 209.89 MWh and 207.56 MWh, respectively. The total reactive energy losses are 38.69 MVArh, 156.87 MVArh and 155.15 MVArh, respectively. A high increase in losses is observed in Case-1 and Case-2 compared to the Base Case. In addition, it is observed that DG integration provides support and decreases loading on the lines, resulting in fewer power losses.

	Active Losses [MWh]	Reactive Losses [MVArh]
Base Case	51.39	38.69
Case-1	209.89	156.87
Case-2	207.56	155.15
	Active Losses [MWh]	Reactive Losses [MVArh]

Table 8. Total grid losses for each case

As seen in Table 9, the regular load growth gives an 80% alert for slightly over 25% of the total transformers. However, when EV load is added, this level goes up to 85%, depicting the significant impact of EV load compared to normal load growth. Furthermore, the relatively low DG capacity positively affects this overloading condition, even though this is only a slightly impact.

	Total number of transformers with load	Number of overloaded transformers (exceeding 80% of capacity)	Ratio of overloaded transformers (exceeding 80% of capacity) [%]
Base Case	2443	629	25.74
Case-1	2443	2086	85.38
Case-2	2443	2073	84.85

Table 9. Transformer overloading ratios for different cases

Feeder overloading analysis

The number of feeders has been increased by more than 20% compared to the 2030 case. In addition, the number of feeders exceeding 20 transformers in a ring configuration, as analysed in this project, is lower than the 2030 case, as seen in Table 10.

Total number of feeders	Number of feeders exceeding 30 transformers	Ratio of feeders exceeding 30 transformers [%]
273	4	1.47

Table 10. Feeder overloading data

3 Concluding remarks and recommendations

This project, encompassing three comprehensive case studies, has provided valuable insights into the dynamic interactions between EV loads, DG, and distribution system constraints. The Base Case study focused solely on inflexible loads, while Case-1 integrated EV loads, and Case-2 extended this integration to include both EV loads and distributed generation resources.

The Base Case study highlighted the significance of addressing distribution system constraints to ensure operational stability. Overloaded circuits and voltage fluctuations were identified as potential challenges, emphasising the importance of careful planning and capacity management.

The consideration of 2030 and 2038 conditions allowed for future-proofing the distribution system. The analysis accounted for the changing grid structure with increased loads and the widespread adoption of EVs and DG, ensuring that the DSO should be well prepared for evolving demands.

Proactively plan and execute strategic grid investments

Since electricity grid infrastructure development requires additional time in comparison to EV and DG implementation, and in order to ensure energy transition needs, grid investments in transformer, line and topology levels should be proactively planned and executed by ensuring operational excellence for customer satisfaction.

Given the anticipated increase in loads and the integration of EVs and DG, the DSO should consider strategic investments in infrastructure such as enhancing the options for increased flexibility (grid scale batteries, responsive demand and vehicle-to-grid capabilities), more digitisation progress, etc. Upgrading and reinforcing the grid capacity will be crucial to meet the growing demands effectively.

Some of the main steps that need to be taken to integrate EVs and DG into the existing distribution grids are discussed in detail below.

Develop flexibility markets

The development of flexibility markets is crucial for handling the variability of renewable energy and electric vehicle (EV) charging demands. In these markets, ‘prosumers’ —individuals who both use and generate energy — can either sell their surplus energy or modulate their consumption based on grid requirements.[17] This not only offers a financial benefit for prosumers but also helps DSOs in managing power supply and demand more efficiently.

However, this model possesses challenges, as the incentive to use batteries for self-consumption often does not align with broader grid benefits, potentially leading to unpredictable energy contributions and grid instability. Some suggest mandating complete feed-in of self-produced power to enhance grid predictability. Therefore, to achieve a balanced smart grid system, it is crucial to incentivise prosumers not just for self-consumption but for contributing to grid stability, encouraging them to adapt to price signals and participate in aggregated demand.

Design regulatory frameworks and implement policies to develop smart grid infrastructure

For incentives and flexibility markets to be effective, supportive regulatory frameworks and policies are essential. This includes clear guidelines on energy trading between prosumers and the grid, standardised tariffs for energy bought back by the grid, and policies that support the development of smart grid infrastructure.

According to the DSO examined in the study, the additional load from EV charging stations will have a limited impact on the total load in the network until 2030. However, if the current growth rates of the network continue, the distribution grid may become insufficient in specific areas where EV demand is concentrated, failing to meet the additional load demands. In such cases, the capacities of network elements, such as transformers and feeders, will begin to be strained. To accommodate these additional loads, an increase in the network growth rate will be necessary, which could necessitate more flexible

[17] (Parag & Sovacool, 2016)

and contemporary adjustments in the relevant legislation. For instance, under current regulations, network assets subject to capacity expansion investments are expected to have been in use for at least 15 years. This rule may be too rigid for the upcoming era of widespread EV adoption and could hinder necessary investments. Therefore, it may be appropriate to exempt certain mandatory investments from this rule for a specific period.

Additionally, facilitating amendments in local government and public institution legislation may be required to provide additional agility and expedite the process of establishing new feeders or substations. Some international examples demonstrate how legislative and regulatory frameworks have been adapted to simplify and accelerate permitting and approval processes, reduce the number of required approvals, and consolidate them into a single-window clearance system.

- **Germany: Energiewende (Energy Transition)**

To ensure a rapid and adequate expansion of the distribution grids, the German government has implemented the 'Easter package' reforms which emphasise predictive planning. Additionally, to accelerate grid connection processes, the government has mandated digitalisation and standardisation, particularly for photovoltaic systems as part of the PV strategy. Furthermore, the government seeks to ensure mutual recognition of installers by all grid operators, streamline application procedures, enhance transparency in the connection process and standardise technical connection conditions. All new assets are to be integrated into the grid in a way that benefits both the market and the grid. Part B of this study entails a more detailed description of these processes. [18]

- **European Union (EU) Action Plan for Grids**

The EU Action Plan for Grids includes measures to expedite permitting by providing technical support and guidance to authorities, improving stakeholder engagement and streamlining approvals for transmission and distribution grid projects. It identifies concrete and tailor-made actions. It prioritises Projects of Common Interest (PCIs) through political steering and enhanced monitoring. Additionally, the plan introduces regulatory incentives to support forward-looking investments and increases access to EU funding for grid modernisation. To further support grid development, it focuses on securing supply chains and harmonising industry standards for reliable and efficient infrastructure. [19]

Incentivise smart consumer behaviour and accommodate dynamic tariffs

In addition to the key findings and recommendations for integrating EVs into the power distribution network with proactive investments for grid enhancement, there is also significant potential for leveraging incentives for smart consumer behaviour and developing flexibility markets. This approach is crucial for optimising network operations and ensuring a sustainable energy transition.

Electric vehicle charging at peak times creates the most critical situation for disrupting the normal operation of the network. Managing the charging times of EVs can prevent further congestion during these peaks.

Encouraging consumers to engage in smart energy usage behaviours can significantly alleviate the network load, especially during peak hours. Incentives could include dynamic pricing models where consumers benefit from lower tariffs during off-peak hours. This would motivate EV owners to charge their vehicles at times when the network is underutilised, effectively flattening the load curve. Additionally, providing financial incentives or rebates to consumers who install smart home energy management systems can promote energy efficiency and reduce overall consumption.

While avoiding peak times could regularise the load profile on primary feeders, it might also lead to increased simultaneity and worsen the situation locally (in transformers or secondary feeders). Therefore, tariff incentives should be carefully considered, and their implementation may be more appropriate after sufficient observation of user behaviours. Dynamic tariff structures that continuously monitor load and vary according to time and location (even if they require additional monitoring investments) could be a good solution for this situation.

Allow a reserve capacity in the network for EVs in the integration phase and make regulatory changes to ease further adaptation

Until EVs become widespread, estimates related to the future EV load on the network, charging station loading profiles, and the simultaneity coefficients for charging stations remain theoretical. These values can only be determined more accurately through empirical methods after EVs become more common. Thus, considering a reserve capacity in the network investments planned and established for this purpose will be beneficial as a safety

[18] (BMWK, 2021)

[19] (European Commission, 2023)

margin. In legislations like the Electrical Internal Installations Regulation, Electric Facilities Project and Acceptance Regulation, etc., it may be necessary to create a legal basis considering this issue (leaving reserve capacity in network investments until the simultaneity coefficients and loading profiles are clarified).

Similarly, relatively large loads from charging stations, shopping malls and other businesses, which alter the load profile to an unmanageable extent, could be restricted until network investments are made. These businesses could be tasked with managing, optimising and limiting their loads to draw power within specified limits. Charging station operators, in particular, could be mandated to install protective devices to prevent exceeding determined power levels, or alternatively, they could be billed at a penalising or higher rate for exceeding these levels. Charging station operators may want to equip their stations with energy storage systems to balance their consumption profiles. Incentivising the equipping of charging stations with energy storage systems could also be beneficial. In such a case, rather than worsening the load demand curve, the presence of charging stations equipped with energy storage systems could have a corrective effect on it.

Moreover, the widespread adoption of EV charging can have effects beyond the need for additional capacity on the electrical network's technical quality (phase imbalances, harmonics, voltage imbalances, etc.). Therefore, additional technical requirements may need to be imposed for the connection of electric vehicle charging stations to the network. With the inclusion of new factors such as EVs, heat pumps and distributed generation, a need for topology changes is anticipated in the low and medium voltage levels, in addition to organic growth and expansion in the network. Although this study does not include analysis at the low voltage level, considering topology change alongside transformer and line investments in long-term investment plans is of critical importance. Investments and planning conducted with network operation in mind during this process will facilitate the reduction of outage numbers and durations, enhance customer satisfaction, and enable more efficient development and utilisation of new elements connected to the network, such as EVs and heat pumps.

Accordingly, to manage the financial and operational effects of the additional connection numbers and extra electrical load created by EVs on the network, an increase in the flexibility of legislation relevant to the electric distribution sector is required. This includes enhancing the flexibility of infrastructure legislation related to permits and land allocations in the areas where the network will be established, facilitating support from local governments and public institutions, and raising awareness among industry stakeholders about the need for legislative flexibility and additional regulatory adjustments.

On the other hand, implementing advanced planning tools and capacity management strategies will be essential. This includes forecasting future load patterns, understanding the impact of EV charging, and optimising distribution system operations to accommodate evolving energy demands. Such a planning process may also benefit from coordination with the TSO. The DSO should actively engage with regulatory bodies to establish clear and standardised policies.

Addressing issues related to grid access, charging tariffs, and incentives for both users and utilities will contribute to the seamless integration of EVs and DG. Smart grid solutions, advanced sensors and control mechanisms will enhance the DSO's ability to manage voltage fluctuations, grid stability and demand variability.

In conclusion, this project not only provided a comprehensive analysis of the current and future state of the distribution system but also offered actionable insights for the DSO to navigate the complexities of integrating EVs and DG effectively. By implementing the proposed measures, the DSO can position itself as a proactive leader in the energy transition, ensuring a resilient distribution system with sustainable investments and operation for years to come.

Outlook

While this study has primarily focused on the integration of EVs and DG within the distribution grid, the inclusion of storage systems represents a pivotal future step. Storage solutions, such as batteries, offer significant potential to mitigate peak loads and enhance grid stability, especially during periods of high PV generation. By allowing a reserve capacity in network investments, distribution system operators can accommodate future loads and integrations more effectively.

It is important to note that storage systems, unlike e-mobility, are more of a solution than a challenge. Their integration can provide substantial benefits in terms of reducing peak demand, supporting voltage regulation and improving overall grid resilience. The emergence of battery storage systems in Türkiye, primarily in the form of co-located batteries at the transmission level, with around 30 GW of pre-licences awarded as of July 2024, highlights their growing importance. For storage systems to penetrate the distribution level, market design changes focusing on regional balance management will be essential. Therefore, future research and planning should include comprehensive assessments of storage systems to fully leverage their capabilities in supporting a sustainable and efficient energy transition.

German experiences on distribution grid planning, expansion and operation (Part B)

4 Advances in intelligent distribution grid operation in Germany

In the course of the energy transition, Germany has been strongly pursuing the expansion of renewable energy capacities and electric mobility integration. Experiences from Germany can represent valuable case studies for understanding the challenges and opportunities of integrating EVs and DG into distribution grids. In this chapter, the focus will be on grid-oriented control mechanisms, which play a crucial role in managing the increased complexity and maintaining grid stability, even with increasing decentralisation trends. By examining these experiences, we can gain insights into best practices, technological advancements, and regulatory frameworks that can be adapted for similar efforts in Türkiye.

4.1 Adapting distribution grids to new realities

Germany's drive to decarbonise its energy system has led to a significant shift toward variable renewable energy sources (RE) like wind power and photovoltaics. This shift has been accompanied by increased sector coupling, which integrates electricity, heat, gas, and mobility into a single, interdependent energy system. A large amount of distributed renewable generation is connected to the distribution grid, which at the same time, has to integrate millions of new consumers, such as electric cars, heat pumps, and electrolysers.

This transformation has posed new challenges to today's power systems. The variability and uncertainty of electricity generation from distributed generation and the emergence of new connected loads can lead to increased congestion, especially in high voltage grid levels, as grid expansion often lags behind RE growth.

This has increased the complexity of power system operations and requires more flexibility of the system in order to match electricity demand and renewable supply. DSOs need to address these challenges by expanding, reinforcing, and optimising their grids across all voltage levels. A promising solution involves local and regional balancing between load and generation. By controlling new loads like electric vehicles and heat pumps, DSOs have more flexibility. This helps them meet their duties and may reduce the need for grid expansion to keep the system balanced.

4.2 A new regulation for grid-oriented operation of controllable loads [20]

The grid-oriented control of flexible loads is explicitly stipulated in Section 14a of the German Energy Industry Act (EnWG), which enables DSOs to adjust the power consumption of heat pumps, air conditioning systems, electricity storage units and charging stations for electric cars in the event of grid congestion.

With the aim of making the controllability of the above-mentioned new controllable loads mandatory, Section 14a was updated in July 2022, following a thorough debate on concerns about the scope of the DSOs rights of intervention and possible negative effects on end consumers.

Based on the new legislation, grid operators are allowed to reduce the peak power of controllable loads to a certain extent. This is particularly the case if there is a risk of the transformer of a MV/LV substation being overloaded. The intervention may only take place if this is objectively necessary in order to eliminate hazards or disruptions (e.g. to avoid partial outage) and it may only be carried out for as long and as extensively as necessary. To this end, it must be ensured that the asset can be controlled at all times. Furthermore, all operators of controllable loads in a grid area must be treated equally. The grid operator must document the control measures, including the determination of the grid status. Information on the control measures implemented must be published for each affected grid area on a joint internet platform of German DSOs (www.vnbdigital.de).

The grid operator must also guarantee a minimum power supply so that the systems can continue their operation at a minimum level. The minimum power supply is 4.2 kW for individual assets. In a deviation from this, a higher value of 40 percent of the grid connection power applies for larger heat pumps and air conditioning systems (grid

[20] This section is adapted from dena's publications „Eckpunkte zur Ausgestaltung des § 14a EnWG – ein wichtiger Schritt nach vorne“ and „Netzorientierte Steuerung ermöglicht den weiteren Zubau von Wärmepumpen und Ladestationen“, previously published in January 2023 and January 2024, respectively.

connection power > 11 kW). This ensures that, for example, larger heat pumps in apartment buildings can provide sufficient heat even during an adjustment measure. If several systems are controlled via an energy management system, the minimum outputs granted are weighted with a simultaneity factor of between 0.8 and 0.45.

The use of an energy management system promises the following advantages, among others:

- The EMS can freely distribute the available minimum power supply from the grid between the controllable consumption devices.
- If, for example, power is generated at the same grid connection point with a photovoltaic system during an adjustment measure, this can be used in addition to the available minimum power supply from the grid.

Until now, grid operators often had to refuse the grid connection of larger systems such as heat pumps or charging stations due to capacity shortage. In return for the mandatory §14a participation, consumers can now benefit from faster grid connections, as the new regulation provides grid operators with a tool to manage critical situations more effectively and accelerate the grid connection process.

Nevertheless, the grid operator is still obliged to expand its grid in line with the full capacity of the controllable loads in order to avoid necessary adjustment measures in the first place. The new regulation has been in force since 1 January 2024. Individual questions regarding the standardised implementation of grid-oriented control are still to be clarified by the grid operators in coordination with relevant market partners and the BNetzA over the course of 2024. This also includes the exact calculation of the minimum power supply granted, including the simultaneity factor of the controllable loads.

If a grid operator cannot yet implement grid-oriented control—perhaps due to missing sensors that would allow real-time grid monitoring—they may initially rely on preventive adjustments based on existing grid planning data to reduce the power of controllable loads.Within this, the grid operator may adjust the affected systems for a maximum of two hours per day (e.g. at times of high expected grid utilisation), whereby the minimum supply power must be ensured continually.

This preventive option is limited to a maximum of 24 months from the first use in a grid area and until the end of 2028. From 2029 onwards, all grid operators must be able to implement grid-oriented control in accordance with Section 14a EnWG in their grid area based on actual observations of the grid state.

The drafting of Section 14a was challenging, as the regulation had to take into account various interests and objectives, some of which are in conflict with each other:

- **Efficient use of electricity infrastructure and intelligent expansion**: Grid congestion can be avoided in the medium term by grid expansion, but also in the short term by flexibly adapting consumption to the load flow situation in the grid. This control option helps to utilise the existing grid intelligently and efficiently and thus gain time for necessary expansion measures.

- **Integrate new consumption devices quickly**: Controllable consumption devices must be connected very quickly in large numbers today and in the coming years. Potential grid bottlenecks should not stand in the way of this ramp-up. Controlling consumption devices can optimise the utilisation of the existing low-voltage grid until the grid can be expanded.

- **Maintain convenience for consumers**: For the new technologies to successfully establish themselves in everyday life, it is important that grid bottlenecks do not significantly restrict the use of electric cars, heat pumps and cooling systems. Temporary interventions that are necessary to eliminate bottlenecks must therefore not lead to a noticeable reduction in consumer comfort.

- **Use consumer-side flexibility for RE integration**: The flexibility of new controllable consumption equipment is needed to efficiently integrate weather-dependent RE generation into the system. Further adjustments to operation can, for example, be based on the market prices of the electricity available at the time. Such flexible operation should not be restricted by bottlenecks in the grids.

Ultimately, a double-track strategy is recommended. This consists of the systematic use of alternative, operational options and secondly, the expansion of the electricity grid where necessary. In other words, improving the utilisation of the existing grid through smart control and flexibilization should precede any grid expansion. The flexibilization of electricity demand is a measure that can be implemented in the short term in order to integrate new consumption devices quickly and avoid grid congestion.

5 Predictive distribution grid planning in practice

Connecting and integrating new consumers and renewable energy generators into the distribution grid is key to the energy transition. To achieve this, the DSOs need to reinforce and expand their grids and invest in new grid technologies. To this end, it is also important to adapt distribution grid planning procedures to the new requirements.

5.1 Challenges in grid reinforcement and expansion

As part of its annual survey on the status of German distribution grids, the regulatory authority conducted a survey on the number of connected renewable energy systems (including photovoltaics (PV), wind, biomass, hydropower and other renewable energies) in the grid. As can be seen in Table 11, a considerable increase in RE is expected at all voltage levels and especially in the high-voltage level.

Voltage level	Percentage
High voltage	419%
Medium voltage	180%
Low voltage	266%
Total	**262%**

Table 11. Forecast of renewable energy systems connected to the distribution grid by 2032 (percent). Source: Bundesnetzagentur [21]

This picture changes somewhat when examining DSOs' expectations regarding load changes in their grid. In the same survey, a 10-year time horizon was specified for the high-voltage level and 5 years for medium and low voltage levels. Reports from the interviewed DSOs indicate an expected increase in load, primarily due to e-mobility and heat pumps. Additionally, the lower the grid level, the more DSOs anticipate an overall increase in load, with the low-voltage level being particularly affected.[22]

Given this anticipated surge in all voltage levels, DSOs are called to optimise, reinforce and expand their grids. This comes with a set of challenges, beginning with the limited available hosting capacity of distribution grids. The hosting capacity represents a DSO's available capacity to connect renewable energy plants into the grid. This capacity is constrained by the maximum current of the grid assets (cables/ conductors/ transformers) and specific voltage boundaries. An overcurrent would heat up the assets too much and cause damage to equipment. Similarly, over- and undervoltage can also cause malfunction or even damage to consumers and generators.[23]

German grid operators follow the so-called "NOVA" principle, as established in the Energy Industry Act (EnWG): "**grid optimisation before reinforcement and expansion**". Before building new lines, grid operators maximise the utilisation of existing grid assets through optimisation measures, such as thermal monitoring of overhead lines. Particular attention is paid to "bottleneck regions", where the grid is already overloaded at certain times or could become overloaded in the future.[24]

The main cause of bottlenecks and voltage quality problems at the low and medium voltage level is the high feed-in of DG. In order to facilitate the integration of DG, DSOs must reinforce and expand the grid according to the needs of the installed plants and the newly connected plants, as well as those still in the planning phase.

The lack of coordination between grid expansion and the growth of RE capacity is leading to bottlenecks and delays in connecting new RE plants to the German power grid. Among others, also caused by issues of public acceptance. Furthermore, there are delays due to the complexity and bureaucracy of grid expansion processes, the different political interests, industry and citizens, as well as numerous objections (e.g. noise pollution or landscape impairment).[25]

The German Ministry of Economic Affairs and Climate Action (BMWK) has established the following action fields for effective distribution grid planning and expansion:

- Predictive planning of reinforcement and expansion measures in the distribution grid
- Speed-up of grid connection processes of RE plants and controllable loads
- Acceleration of the smart meter roll-out

[21] (Bundesnetzagentur, 2023)
[22] (Bundesnetzagentur, 2023)
[23] (Deutsche Energie-Agentur, 2012)
[24] (VNB digital, n.d.)
[25] (Schopen, 2022)

- Integration of the new systems in a grid-friendly and market-oriented manner.[26]

Regarding predictive planning, this chapter will focus on lessons learned and the new regulation of this field in Germany.

5.2 Predictive planning of distribution grids

When planning electricity grids, grid operators determine the long-term requirements for secure and efficient grid operation. At the heart of this is the expansion of the distribution grid. Since the amendment of the German Energy Industry Act in 2022, larger DSOs in Germany are legally obliged to carry out a predictive planning of their grids and implement it in line with demand.[27]

This was established with the so called "Easter package", effectively amending the legal framework and specifically Section 14d of the EnWG.[28] Following these amendments, the grid expansion plans of the individual DSOs were published. These are based on regional scenarios coordinated in six planning regions, under consideration of the climate neutrality target for 2045.[29] These plans are submitted to the German regulatory authority, the BNetzA. However, not all of the more than 800 distribution grid operators in Germany have to publish a grid expansion plan; this is mostly directed at the approximately 80 larger DSOs with over 100,000 connected customers. The smaller DSOs are involved in the preparation of the grid expansion plans by providing important information and estimates on their local grids for the larger DSOs.[30]

For each region, the DSOs draw up a joint scenario every two years. In this scenario, the DSOs specify the currently installed capacity of the various generation and consumption assets, such as PV systems or heat pumps; They also provide forecasts for the years 2028 and 2033 as well as for the year 2045.[31] The regional scenarios form the common basis for the grid expansion plans, in which the individual DSOs present their specific expansion measures every two years.

The differences between the planning regions and the involved DSOs are already apparent in the regional scenarios: in rural areas, renewable energies are the main driver for a grid expansion. In cities, electrification in the heating and mobility sectors will cause a massive increase in load.[32] In addition, there are regional peculiarities such as the establishment of data centres, for example in the Frankfurt area.[33] In the end, it is these differences and challenges that make a case for closer cooperation between DSOs. All in all, this first publication of grid expansion plans at the distribution level provides an outlook on future reinforcement needs and supports the idea of predictive reinforcement and expansion in order to speed up the integration of new RE plants.

[26] (BMWK, 2021)
[27] (BMWK, 2024)
[28] (BMWK, 2021)l
[29] (Bundesnetzagentur, 2023)
[30] (VNB digital, n.d.)
[31] (BDEW, 2023)
[32] Ibid.
[33] Ibid

6 Pitfalls during smart meter rollout

One of the key enabling instruments for the newly introduced operation processes described in the previous chapter is smart metering systems. They ensure that distribution grids will continue to be operated safely and efficiently. The smart metering system, consisting of a modern metering device and a smart meter, is subject to a large number of technical regulations. This chapter describes the regulatory background of the German smart meter rollout and highlights the lessons learned during this four-year process.

The complexity of system operation increases the need for effective information exchange and the use of advanced information and communication technologies. This exchange must be reliable, secure, and, in some cases, very rapid. Increasingly, the control of operating resources, generation, and consumption systems is required. This necessitates well-defined processes within a grid, as well as in coordination with other network operators and external market participants.

Smart meters provide the enabling infrastructure for these processes. This subchapter will closely examine the successes and failures of Germany's smart meter rollout. To understand the issues encountered during the introduction of smart meters in Germany, it is important to consider the historical development of smart meter infrastructure.

The smart meter rollout in Germany is based on the EU-Directive 2009/72/EC on common rules for an internal European electricity market, which stipulated back in 2009 that member states must equip 80 per cent of consumers with smart meters by 2020 – in markets with a positive cost-benefit analysis (CBA). The aim was to enable end customers to take measures to increase energy efficiency and save energy by providing them with a transparent overview of their own energy consumption. In Germany, the Act on the Digitisation of the Energy Transition (GDEW) came into force in 2016 and laid the foundation and a binding legal framework for the gradual expansion of a smart energy grid in Germany.

At the core of the GDEW is the Metering Point Operation Act (Messstellenbetriebsgesetz, MsbG) from 2016, which regulates how and when the previous analogue electricity meters are to be replaced by smart metering systems (smart meter rollout). The rollout plan includes different rollout periods for different types of end consumers and plant operators categorised either by energy consumption or size of generation assets owned and operated.[34] It requires that consumers with an annual consumption of more than 6,000 kWh and plant operators with an installed capacity of more than 7 kW must be equipped with smart meters. Below these thresholds, smart meters are not mandated. The MsbG also includes specific requirements about collecting, transmitting, and using the metering data. Minimum technical requirements and specifications for the protection of smart metering systems are also described. Furthermore, it stipulates that smart meter gateways (SMGW) from at least three manufacturers need to be certified by the Federal Office for Information Security (Bundesamt für Sicherheit in der Informationstechnik, BSI) so that users and customers have a choice.[35] [36]

The smart meter rollout was initially scheduled to begin in 2017 but was delayed until January 2020 due to significant delays in the certification of intelligent metering systems. These delays were attributed to the need to fulfil all safety and security requirements for the smart metering system (iMSys) and the lack of target dates or a cost framework for the certification process[37]

The certified smart meters approved at this stage only offered the same functions as previous meters (such as special time-of-use tariffs and consumer information, via display or apps), except for the transmission of measured data. Essential features for smart grids, like dynamic electricity price contracts, generation and load management, and grid-supporting applications, were limited or non-existent.[38] Thus, the first generation of iMSys did not provide significant added value to customers. Figure 33 below shows an overview of the currently available modern metering devices, their functions, and the roles of responsible operators and market participants. So far, the smart meter rollout in Germany has mainly involved modern metering devices

[34] (Bundesverband Neue Energiewirtschaft, 2020)
[35] Ibid.
[36] A smart metering system (iMSys) consists of a "modern metering device" (mMe) and its connection to a communication network via a "smart meter gateway" (SMGW). A SMGW essentially connects the electricity meter and flexible consumption and generation devices to the smart grid. The mMe collects data relevant to the energy industry, while the SMGW controls secure data transmission and data storage.
[37] (Bundesverband Neue Energiewirtschaft, 2020)
[38] Ibid.

(without SMGW) rather than fully functional smart meters with SMGW.

Before the introduction of the first generation of iMSys, metering systems already available on the market met comparable security and data protection standards and complied with international or industry standards. However, with the BSI-approved iMSys introduction, these existing smart meters were deemed non-compliant with legal standards and could no longer be installed.

This led to a lawsuit from various companies, resulting in an emergency order from the Higher Administrative Court in March 2021, halting the obligation for high-consumption households and companies to install smart meters. The legislator responded quickly by amending the MsbG, allowing the smart meter rollout to resume despite gaps in the framework.

To remedy this, the Act to Restart the Digitisation of the Energy Transition (GNDEW) came into force in May 2023. The law includes amendments to several existing regulations, such as the Energy Industry Act (EnWG) and the Renewable Energy Sources Act (EEG). However, the most extensive changes were made to the Metering Point Operation Act. The focus here is on the accelerated and simplified rollout of the communication infrastructure. The rollout is of particular importance as it is the basic prerequisite for data collection and therefore for all applications based on it in a digitalised energy industry.

With regard to the timetable, the GNDEW has defined a mandatory rollout timetable for the installation of the metering systems, stipulating that at least 95 per cent of consumers and producers will be equipped with an iMSys by 2030 or 2032 (depending on the size of consumption or installed capacity). The valuable lessons learned during the smart meter rollout in Germany, can facilitate the future speed-up of such a process and can also be a reference for Türkiye. The main lessons learned in this respect are summarised as follows:

- Set realistic requirements regarding the safety and security of the smart metering system that include existing metering systems available on the market but also to foster new and innovative smart meter technology.
- Set target dates and a cost framework for the smart meter certification process to avoid an unnecessarily costly and lengthy rollout.

In conclusion, the slow rollout of smart meters also slowed down the digitisation of distribution grids, crucial for the next phase of the energy transition. Nonetheless, Germany has significant potential to develop smart meters as tools enabling consumers to play a more active role in a smart, decentralised grid system.

	Ferraris meter	Modern meter	Smart meter	Communication unit = Smart meter gateway
Type of meter	Analogue meter	Digital meter without communication unit	Digital meter with communication unit	Communication interface
Meter functions	• Current meter reading to be replaced by 2032 at the latest	• Current meter reading • Stored values > daily values > weekly values > monthly values > yearly values Two years in retrospect can be upgraded to a smart meter by integrating a communication unit	• Current meter reading • Quarter-hour values > for each day > week > month > year	• Interface between meter and communi-cation network • Can connect up one or more meters • Automatic transfer of data to metering point operator
Entity res-ponsible for installation, metering and technical ope-ration	Local grid operator	Competent local metering point operator (usually the local grid operator) or a metering point operator contracted by the consumer		Smart Meter Gateway Administrator (either the competent local metering point operator or a market competitor)

Figure 33. Overview of current metering devices in Germany. Source: BMWK (2021)

ANNEX

Renewable Energy Sources Support Mechanism (YEKDEM in Turkish)

The usage of renewable energy in electricity generation in Türkiye has become widespread primarily with hydroelectric power plants. The installed capacity of renewable energy other than hydroelectric power plants increased with the 'Renewable Energy Resources Support Mechanism' (YEKDEM), which entered into force in 2011. The first YEKDEM (YEKDEM v1.0) was introduced as a USD-based incentive mechanism. It is a resource-based fixed-price scheme to increase the installed capacity of renewable energy power plants. This mechanism aims to incentivise the renewable energy sector to reduce dependence on imported energy sources and minimise the current account deficit. The implementation period of the YEKDEM prices has been determined as 10 years for generation facilities. At the same time, for 5 years, power plants benefitted from an additional domestic contribution share according to the rate and type of domestic component utilisation.

On 30 January 2021, the Official Gazette announced the tariffs and periods to be applied under the new YEKDEM. The new YEKDEM (YEKDEM v2.0) includes renewable power plants to be commissioned between 1 July 2021 and 31 December 2025. It provides a purchase guarantee in Turkish Lira for renewable generators. It was also announced that the tariffs will be updated every quarter with a set escalation method. However, since no capacity auctions were announced under the new YEKDEM and the incentive mechanism was designed in TL, the capacities commissioned under the new YEKDEM remained limited.

With the decree dated 1 May 2023, base prices and methodology were changed and started to be updated monthly. With the update (YEKDEM v3.0), the prices are revised monthly depending on the PPI, CPI and dollar and euro exchange rates. The implementation period of the revised YEKDEM prices is set at 15 years for geothermal power plants and pumped storage hydroelectric facilities, and 10 years for other types of facilities. The implementation period of the Local Component Support Prices has been set at 5 years for hydroelectric, wind, geothermal, biomass and solar power plants and 10 years for wind or solar power plants with storage, hydroelectric power plants with pumped storage and generation plants based on wave. With the revised mechanism, new renewable energy technologies, including offshore wind power plants, electricity storage facilities integrated with wind or solar energy, pumped hydroelectricity facilities, and electricity generation plants based on wave or current energy sources, were priced separately for the first time under YEKDEM and Local Component Support Prices.

It is important to note that currently, there are power plants that benefit from the USD-based YEKDEM v1.0. The reason for this is that there are existing power plants that were commissioned before June 2021 and promised to continue for 10 years.

Additionally, settlement for YEKDEM power plants is performed monthly. For YEKDEM participants, income and cost calculations are made in return for the generation within the scope of YEKDEM. In all circumstances, YEKDEM power plants receive the DAMP in the day-ahead market. If the YEKDEM price is higher than the DAMP, the deficit amount is paid to the YEKDEM power plants in the month-end settlement. If the DAMP is more than the YEKDEM the excess amount is paid back to EPİAŞ, which is the market operator responsible for operating the day-ahead and intraday markets in Türkiye.

Within the feed-in tariff period, renewable energy power plants receive daily income from the market operator based on the day-ahead market prices. The difference between the FiT and day-ahead market prices is calculated and paid to these facilities through the YEKDEM unit cost which is paid by all electricity end-users. The YEKDEM unit cost is calculated according to the remaining cost that had to be paid to YEKDEM power plants and YEKDEM Base National Demand. The high market prices have recently caused negative YEKDEM unit costs. However, with the regulation amendment dated 1 March 2022, it has been decided to transfer the collected amount to the designated retailed companies, not the end-users.

$$YEKDEM\ Payment\ Difference\ = Total\ Net\ Generation * \{(FiT * USD\ Exchange\ Rate) - (DAMP^{39} * Tolerance\ Coefficient^{40})\}$$

In short, the usage of renewable energy in Türkiye is of great importance in the context of combating climate change, reducing imported fuel dependency on energy

[39] Hourly basis DAMP is taken into consideration.

[40] The tolerance coefficients vary according to the type of renewable energy source. They are determined as 0.970 for wind, 0.980 for solar and RoR, 1.000 for reservoir hydro, 0.995 for geothermal and 0.990 for biomass.

and utilising domestic resources. With the updated YEKDEM, an important step has been taken to increase the viability of renewable energy investments and energy investment models in the market.

Mathematical Model

The details of the employed MIQCP based optimisation model are as follows:

Objective Function

Equation 1

$$min: \sum_t \sum_i \sum_j (\mathcal{P}^{loss}_{i,j,t} + Q^{loss}_{i,j,t})$$

Aiming at minimising the total losses in the distribution system, an objective function as given by Equation 1 is proposed.

Power Balance Equations

Equation 2

$$\mathcal{P}^{subs}_{i,t} + \sum_d \mathcal{P}^{DG,unit}_{d,i,t} + \sum_{j\in\Omega^j_i} f^P_{i,j,t} - \sum_{j\in\Omega^i_i} f^P_{i,j,t} = \mathcal{P}^{demand}_{i,t} + \mathcal{P}^{EV}_{i,t} + \sum_{j\in\Omega^j_i} \mathcal{P}^{loss}_{i,j,t}, \qquad \forall t$$

Equation 3

$$Q^{subs.}_{i,t} + \sum_d Q^{DG,unit}_{d,i,t} + \sum_{j\in\Omega^j_i} f^{reactive,Q}_{i,j,t} - \sum_{j\in\Omega^i_i} f^{reactive,Q}_{i,j,t} = Q^{demand}_{i,t} + \sum_{j\in\Omega^j_i} Q^{loss}_{i,j,t}, \qquad \forall t$$

Equation 2 and Equation 3 state the active/reactive power balances for all buses consisting of injected power from a substation bus, the output power of a stationary DG unit and power flows in the branches with demanded power of loads (consisting of heat pumps) and EV charging needs as well as power losses. The active power which flows from bus i to bus j (mirror set of nodes) and is sent to load buses from slack bus i are included in Equation 2 represented as $\sum_{j\in\Omega^j_i} f^P_{i,j,t}, \sum_{j\in\Omega^i_i} f^P_{i,j,t}$, respectively.

Power Losses and the Restrictions

Equation 4

$$\mathcal{P}^{loss}_{i,j,t} = R(i,j) \cdot \frac{(f^{active,P}_{i,j,t})^2 + (f^{reactive,Q}_{i,j,t})^2}{{V_0}^2}, \forall t$$

Equation 5

$$Q^{loss}_{i,j,t} = X(i,j) \cdot \frac{(f^{active,P}_{i,j,t})^2 + (f^{reactive,Q}_{i,j,t})^2}{{V_0}^2}, \forall t$$

Equation 6

$$0 \le \mathcal{P}^{subs.}_{i,t} \le \mathcal{P}^{subs.,max}_i, \qquad \forall t$$

Equation 7

$$0 \le Q^{subs.}_{i,t} \le Q^{subs.,max}_i, \qquad \forall t$$

Equation 8

$$V^{bus}_{i,t} - V^{bus}_{j,t} = \frac{R(i,j) \cdot f^{active,P}_{i,j,t} + X(i,j) \cdot f^{reactive,Q}_{i,j,t}}{V_0} - (R(i,j)^2 + X(i,j)^2) \cdot \frac{\left(f^{active,P}_{i,j,t}\right)^2 + \left(f^{reactive,Q}_{i,j,t}\right)^2}{2V_O^3}, \forall t$$

Equation 9

$$V^{min}_i \le V^{bus}_{i,t} \le V^{max}_i, \quad \forall i, \forall t$$

Equation 4 and Equation 5 calculate the active/reactive power losses consisting of quadratic components of corresponding flows multiplying with parameters of resistance/reactance of the branch divided into nominal voltage V_0 of the system. Also, it should be emphasised that the active/reactive power injection from the upstream grid cannot exceed the maximum capacity constraint as indicated in Equation 6 and Equation 7.

Regarding the operational constraints of the distribution system, the voltage drop between bus i to bus j is calculated based on the function of the parameters of reactance and resistance of the branch (i,j) and the related power flows as expressed in Equation 8. Also, the upper and lower bounds of voltage are set in Inequality Equation 9 for all optimisation executions.

Equation 10

$$-S_{i,j}^{max,cap} \leq f_{i,j,t}^{active,P} \leq S_{i,j}^{max,cap}, \qquad \forall t$$

Equation 11

$$-S_{i,j}^{max,cap} \leq f_{i,j,t}^{reactive,Q} \leq S_{i,j}^{max,cap}, \qquad \forall t$$

Equation 12

$$-\sqrt{2}\,S_{i,j}^{max,cap} \leq f_{i,j,t}^{active,P} + f_{i,j,t}^{reactive,Q} \leq \sqrt{2}\,S_{i,j}^{max,cap}, \quad \forall t$$

Equation 13

$$-\sqrt{2}\,S_{i,j}^{max,cap} \leq f_{i,j,t}^{active,P} - f_{i,j,t}^{reactive,Q} \leq \sqrt{2}\,S_{i,j}^{max,cap}, \quad \forall t$$

On the other hand, the expressions Equation 10, Equation 11, Equation 12 and Equation 13 refer to the limitation of the active/reactive power flow level depending on maximum branch apparent power value. Normally, they have a non-linear structure, and a circular constraint linearisation technique is used to linearise them. Two quadratic constraints are taken into consideration in this method which gives quite accurate results in engineering applications.

Here, it should be stated that this power flow model is mainly MV-level oriented and the DG and EV integration directly to LV-level users can either be cumulatively modelled at the MV level or a sub-LV level.

Analysis of individual load factors (2023 case analysis)

In this section, further examples behind the analysis of the LF values for each charge level (as seen in Table 1) are provided. The impact of all the EV levels is conducted separately for each case since the connection bus of each one is different. For instance, low-level EV charge power is available on Bus-1124 for the 2023 Case. It is observed that the average power consumption during the day for the Base Case, Case-1, and Case-2 is 4.204 MVA, 4.211 MVA and 4.211 MVA, respectively, while the maximum power demands for the same cases are 5.217 MVA, 5.224 MVA, and 5.224 MVA, respectively. In this way, the LF values of low EV charge for each case can be analysed. On the other hand, medium- and high-level EV charge powers are integrated in Bus-606 and Bus-1247, respectively. The average power consumption of medium-level EV demand for the Base Case, Case-1, and Case-2 is 2.384 MVA, 2.405 MVA and 2.405 MVA, respectively, while the maximum power demands for the same cases are 3.204 MVA, 3.225 MVA, and 3.225 MVA, respectively. Similarly, the average power consumption of high-level EV demand for the Base Case, Case-1, and Case-2 is 2.547 MVA, 3.329 MVA and 3.325 MVA, respectively, while the maximum power demands for the same cases are 2.937 MVA, 3.719 MVA and 3.719 MVA, respectively. As can be seen from the results, the variable EV demands are available on different buses, which have different loading profiles, resulting in different average consumptions and maximum powers.

Pre-results of a sample 240-bus test system

In this section, the impact of EV and HP loads, as well as wind and solar energy-based DG, on a sample 240-bus distribution system are investigated in terms of distribution line loading, load factor and bus voltages. Additionally, total power losses are analysed for different scenario studies. Three case studies are considered in this analysis. These cases are as follows:

- Base Case: Operation of the distribution system without EV, HP and DG integration.
- Case-1: Operation of the distribution system with EV and HP, without DG integration.
- Case-2: Operation of the distribution system with EV, HP and DG integration.

The sample 240-bus distribution system is modified in order to use the test data for the test studies. In Figure 34, the modified test system is demonstrated. The EV parking lots (EVPL) in this test system, assigned EVPL-1 and EVPL-2, serve 50 and 100 EVs, respectively. They are located at different buses. Furthermore, the system incorporates a wind power plant (WPP), which has a power of 50 kWp, and a photovoltaic plant (PVP), which has a power of 100 kWp, as DG resources. The distribution system as a whole consists of 15 HP units. Figure 37 shows the temporal profile of the HP and EV demand and DG generation in the system.

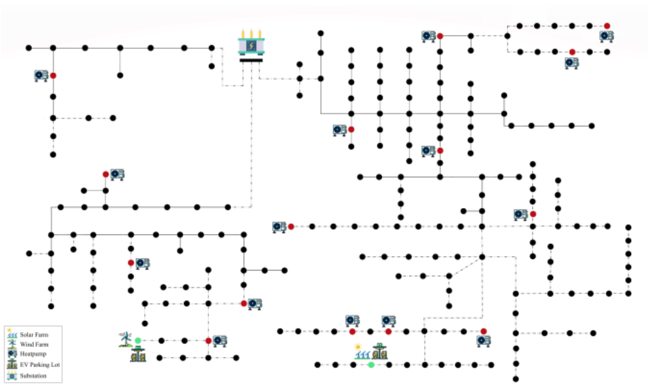

Figure 34. Modified version of a sample 240-bus distribution test system

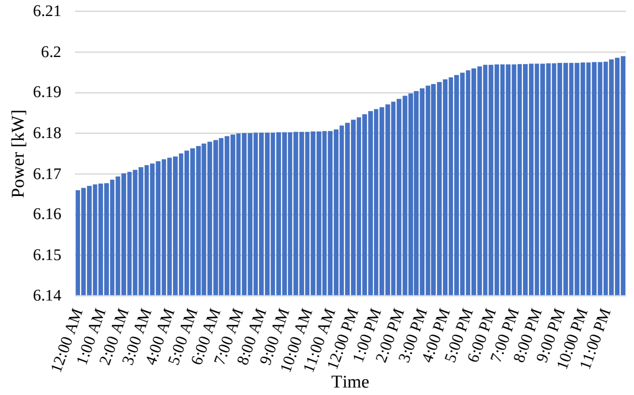

Figure 35. The variation of HP load

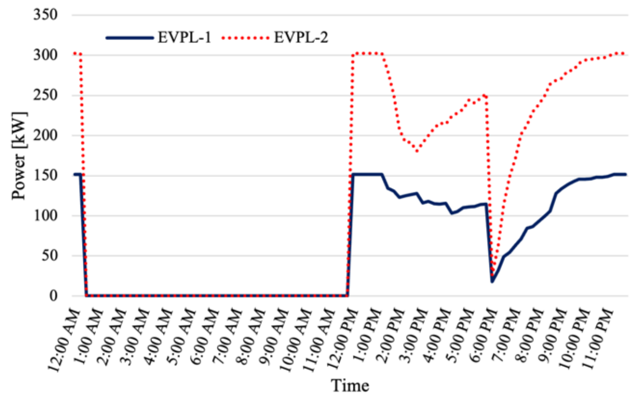

Figure 36. The variation of EV load

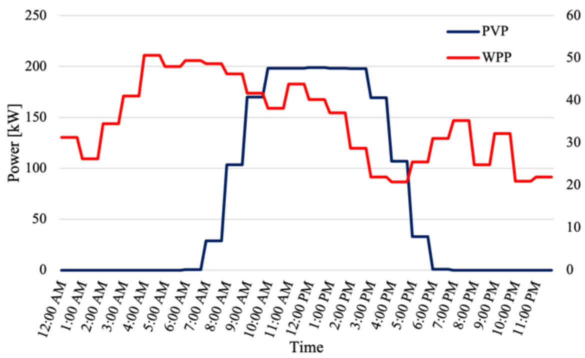

Figure 37. The variation of DG-based generation

Line loading analysis

In Figure 38, loading profiles of the line where a parking lot consisting of 50 EVs, a HP load, and a 50-kW installed-capacity WPP are connected, are depicted for each case study. The impact of EVs and HPs on the loading of the distribution line is observed in Case-1 compared to the Base Case in which the new load types and DG connection are not considered. On the other hand, peak loads are significantly reduced as the EV and HP loads are locally supplied with the DG connection in Case-2. The peak load of 157.73 kva occurring at 12:00 PM in Case-1 is reduced to 117.52 kva in Case-2, achieving a 25.49% reduction in peak load. Additionally, bi-directional power flow to the main grid is realised as the PVP generation exceeds the demand between 1:00 AM and 12:00 PM. Since the apparent power flowing through the line is handled here, the apparent power takes a positive value while the active power is negative.

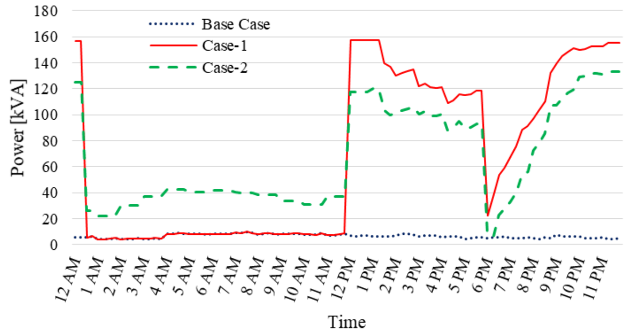

Figure 38. Loading profiles of the line connected to the bus with 50 EVs, a HP load and a 50-kW installed-capacity WPP

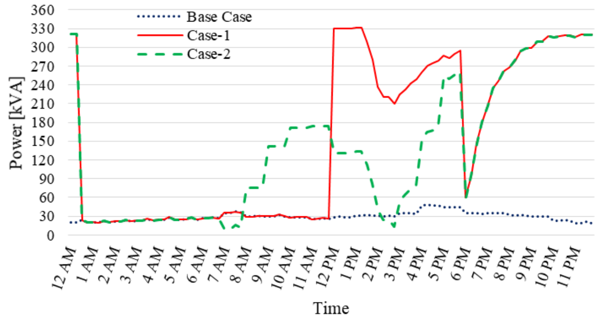

Figure 39. Loading profiles of the line connected to the bus with 100 EVs, HP load, and a 200-kW installed-capacity PVP

The loading profiles on the line where a parking lot consisting of 100 EVs, a HP load and a 200-kW installed-capacity PVP are connected, are shown in Figure 39 for each case study. Similar to the previous scenario studies, in Case-1, the power flowing through the line is significantly higher than the Base Case due to the EV and HP loads. In Case-2, the high loading is reduced through the PVP, and excess net energy is fed back to the grid. Unlike the first scenario, the peak load reduction ratio is increased in the second scenario due to both demand-side flexibility and the integration of high-capacity DG, despite the higher number of EVs. The peak load of 332.08 kva occurring at 1:00 PM in Case-1 is reduced to 133.85 kva in Case-2, achieving a 59.69% reduction in peak load.

Load factor analysis

The load factor values for all case studies in two separate scenarios are examined in Table 12. It is observed that the load factor reduces for both scenarios if EV and HP loads are included in the grid planning. The main reason behind this is the tendency of new-generation demand types to intensify at certain times, leading to high peak loads. In the first scenario, the load factor is calculated as 65.77% for the Base Case and 43.34% for Case-1, while it is 61.22% for the Base Case and 46.68% for Case-1 in the second scenario. Furthermore, it is noted that the impact of DG integrations varies with installed power capacity. For instance, the load factor increases to 50.41% compared to Case-1 in the first scenario after integrating a 50 kW WPP, whereas it decreases to 41.97% compared to Case-1 in the second scenario after integrating a 200-kW PVP. The underlying reason for this lies in the fact that the average power flowing through the line decreases in high-DG availability, while the maximum peak load value remains the same or close to it.

Load Factor (%)	50 EVs+HP+ 50-kW WPP	100 EVs+HP+ 200-kW PVP
Base Case	65.77	61.22
Case-1	43.34	46.68
Case-2	50.41	41.97

Table 12. Load factor of the cases

Voltage analysis

Figure 40 shows the voltage profile of a bus with 50 EVs, a HP load and a 50-kW installed-capacity WPP for each of the three cases. The voltage of the bus is seen to be roughly 1.049 p.u. during periods of low load demand in the Base Case. When load demand is high during the day, it decreases to 1.048 p.u. The total voltage deviation at this bus is determined to be 0.14 p.u. In Case-1, late at night and in the early evening when EV demand is high, there is a noticeable voltage drop at the bus compared to the Base Case. By evening, the voltage drops to 1.047 p.u. Compared to Base Case, there is a 50% greater voltage deviation observed during the day. The system's load demand rises with the incorporation of EV and HP loads. Voltage drops increase along with load demand. DG (WPP) integration in Case-2 generates a voltage profile between 1 AM and 12 PM that is remarkably similar to the Base Case. For the remainder of the time, there is a lower voltage drop than in Case-1. There is a 14% decrease in the overall voltage deviation when compared to Case-1.

In all three scenarios, the voltage profile of a bus with 100 EVs, a HP load and a 200-kW installed-capacity PVP is shown in Figure 41. The voltage level of the bus is 1.044 p.u. when there is limited load demand in the Base Case. As the load increases throughout the day, the voltage decreases to 1.039 p.u. Compared to the previously examined bus, this bus is further from the substation, which results in a higher voltage drop. The voltage deviation at the bus is found to be 0.77 p.u. overall. The voltage profile of the bus differs from the Base Case starting at 12 PM in Case-1. In the late afternoon and evening, the voltage decreases to 1.036 p.u. The voltage deviations exceed the Base Case by 23%. The addition of EV and HP loads increases the load demand on the system. As load demand rises, voltage drops also rise. Since Case-2 contains PVP, DG production is limited to daytime hours. Consequently, an improvement in the voltage profile is only observed during the day. Additionally, from 9 AM to 12 PM, voltage rises in comparison to other times. The overall voltage drop is 7.5% lower than in Case-1.

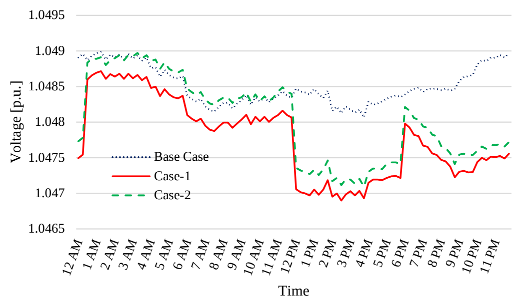

Figure 40. Voltage profiles of the buses with 50 EVs, a HP load and a 50-kW installed-capacity WPP

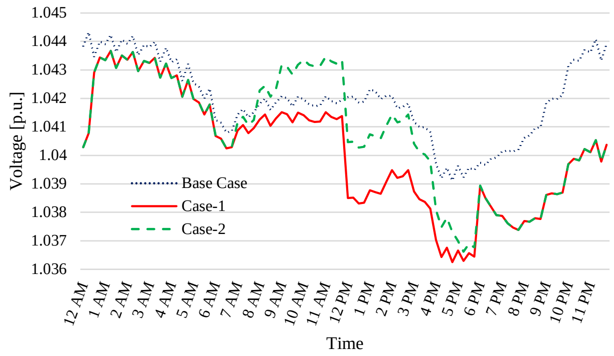

Figure 41. Voltage profiles of the buses with 100 EVs, a HP load and a 200-kW installed-capacity PVP

The voltage profile at 4 PM in all buses is displayed in Figure 42. The voltage drops from 1.05 p.u. at the beginning of the line to 1.04 p.u. at the end in the Base Case. In Case-1, examining the voltage profiles of all buses reveals that the voltage level is lower than in the Base Case. In Case-2, with the integration of DG plants, the voltage profile is seen to improve in all buses.

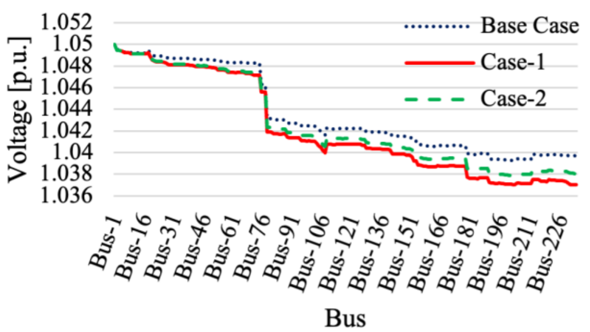

Figure 42. Voltage profile of the whole test system at 4 PM for all cases

Power losses analysis

The total grid losses for each case study are presented in Table 13. The total active and reactive grid losses are 142.84 kWh and 142.84 kVArh in the Base Case where EV and HP loads are not taken into account. In Case-1, the total losses are increased as expected, reaching values of 222.01 kWh and 222.01 kVArh. However, the increase in losses caused by the new-generation demand loads is mitigated through the DG integrations. In this case, active and reactive energy losses are reduced by 11.47% compared to Case-1, reaching values of 196.55 kWh and 196.55 kVArh.

	Active Losses [kWh]	Reactive Losses [kVArh]
Base Case	142.84	142.84
Case-1	222.01	222.01
Case-2	196.55	196.55

Table 13. Power losses across the distribution system lines

The detailed analysis of the 240-bus test system, encompassing different scenarios of EV and HP loads, as well as the integration of wind and solar-based DG, provides significant insights into the model's effectiveness and its applicability to real-world scenarios. Here is a summary of the key findings and their implications for validating the model:

- Impact on Line Loading and Load Factor: The model successfully demonstrates the varying impacts of different load types and DG integration on line loading and load factor. In scenarios with EV and HP integration, a noticeable increase in peak loads and a reduction in load factor are observed. This highlights the model's capability of accurately capturing the dynamics of new-generation demand types.
- Voltage Profile Analysis: The voltage profiles under different scenarios reveal the model's sensitivity to changes in load and generation. The voltage drops and deviations across various cases, particularly with the addition of EV and HP loads, show the model's adeptness in reflecting real-world voltage behaviour in a power distribution system.
- Power Losses Assessment: The analysis of total grid losses under each scenario validates the model's ability to quantify the impact of EV, HP and DG integration on the system's efficiency. The reduction in losses with DG integration is a critical finding, underscoring the model's effectiveness in evaluating the benefits of renewable energy sources.
- Model's Applicability and Realism: The consistent trends and logical outcomes in different scenarios indicate that the model is not only valid but also realistic. It mirrors the expected behaviour of a distribution system under varying loads and generation patterns, thereby proving its suitability for conducting real case studies.

In conclusion, the results from the 240-bus test system analysis confirm the validity and effectiveness of the model. It has been successfully proven to work and is suitable for conducting real case studies. The findings not only reinforce confidence in the model's capabilities but also provide a valuable framework for understanding and managing the challenges associated with the integration of EVs, HPs and DG in power distribution networks.

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List of figures

List of tables

Abbreviations

AC: Alternating current

BO: Build Operate

BOT: Build Operate Transfer

BMWK: German Ministry of Economic Affairs and Climate Action

BNetzA: German Federal Network Agency

CBA: Cost-Benefit Analysis

DC: Direct current

DG: Distributed Generation

DSO: Distribution System Operator

EEG: German Renewable Energy Sources Act

EML: Electricity Market Law

EMRA: Energy Market Regulatory Authority

EnWG: German Energy Industry Act

EU: European Union

EÜAŞ: Electricity Generation Company

EVs: Electric Vehicles

BSI: German Federal Office for Information Security

GDEW: German Act on the Digitisation of the Energy Transition

GNDEW: German Act to Restart the Digitisation of the Energy Transition

HP: Heat pumps

iMSys: Smart Metering System

kW: Kilowatt

LPG: Liquefied Petroleum Gas

mMe: Modern Metering Device

MsbG: German Metering Point Operation Act

MVA: Megavolt-ampere

MWh: Megawatt hour

PCIs: Projects of Common Interest

p.u. : per unit

PV: Photovoltaic

PVP: Photovoltaic Power

SMGW: Smart Meter Gateway

TEAŞ: Turkish Electricity Generation Transmission Company

TEDAŞ: Turkish Electricity Distribution Company
TEİAŞ: Turkish Electricity Transmission Company
TEK: Turkish Electricity Authority
TETAŞ: Turkish Electricity Trading and Contracting Company
TOR: Transfer of Operating Rights

Glossary

Alternating Current (AC): An electric current that periodically reverses direction.

Bus (Busbar): A conductor, or group of conductors, that collects and distributes electric power in a power system. It serves as a common connection point for multiple circuits.

Carbon Border Adjustment Mechanism: An emerging bipartisan tool that aims to cut global pollution and support American industry, A CBAM is a fee applied to products upon entry or import that accounts for the amount of greenhouse gases emitted during their production in their country of origin.

Decentralised Generation: A decentralised energy system characterized by locating energy production facilities closer to the site of energy consumption. A decentralised energy system allows for more optimal use of renewable energy as well as combined heat and power, reduces fossil fuel use and increases eco-efficiency.

Demand Response Programmes: Programmes designed to encourage consumers to change their electricity usage patterns in response to price signals or other incentives.

Direct Current (DC): An electric current that flows in one direction only.

Distributed Generation (DG): The generation of electricity by small-scale power plants located close to where the electricity is used, rather than by large central plants. These plants often use renewable energy sources such as solar or wind power.

Distribution System Operator (DSO): An entity responsible for operating, ensuring the maintenance of, and developing the distribution system in a given area and, where applicable, its interconnections with other systems.

Electric Vehicles (EVs): Vehicles that are propelled by electric motors using energy stored in batteries or another energy storage device.

Electrification: Electrification means replacing technologies or processes that use fossil fuels, like internal combustion engines and gas boilers, with electrically powered equivalents, such as electric vehicles or heat pumps.

Energy Storage: Energy storage is the capturing and holding of energy in reserve for later use.

Energy Transition: The process of shifting from a fossil-fuel-based energy system to one that relies more on renewable energy sources.

Feed-in Tariff (FiT): A policy mechanism that offers long-term contracts to renewable energy producers, typically based on the cost of generation of each technology, providing a guaranteed purchase price for the electricity generated.

Flexibility Markets: Markets that allow for the trade of electricity flexibility, including adjusting production or consumption in response to grid demands.

Grid Congestion: Occurs when demand for electricity exceeds the capacity of the transmission or distribution network, leading to potential reliability issues or the need for load management.

Load Factor: The ratio of the average load over a designated period of time to the peak load occurring in that period, indicating the efficiency of the electrical system usage.

Megawatt-hour (MWh): A unit of energy equivalent to one megawatt (1 MW) of power used continuously for one hour.

Mitigation: Mitigation – reducing climate change – involves reducing the flow of heat-trapping greenhouse gases into the atmosphere, either by reducing sources of these gases or enhancing the ‘sinks’ that accumulate and store these gases.

Peak-Shaving: The process of reducing the amount of energy consumed during peak usage times, often through the use of energy storage systems or by shifting consumption to off-peak times.

Photovoltaic (PV) Systems: Systems that convert sunlight directly into electricity using semiconducting materials.

Power Losses: Energy losses that occur during the transmission and distribution of electricity due to the resistance of electrical components.

Power Purchase Agreement (PPA): A contract between a power producer and a buyer (often a utility or large power consumer) outlining the terms of the sale of electricity.

Smart Grid: An electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users.

Topology: The physical layout and arrangement of the elements in an electrical network, such as lines and transformers.

Transformer Overloading: A condition where a transformer operates above its rated capacity, which can lead to overheating and potential damage.

Voltage Profile: The variation of voltage magnitude at different points along an electrical system, often plotted as a graph.

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