smartEn
Smart Energy Europe

DEMAND-SIDE FLEXIBILITY

Quantification of benefits in the EU

DNV

ABOUT SMARTEN

smartEn is the European business association for digital and decentralised energy solutions. Our members include innovators in services and technology for energy and data management, finance, and research. By taking an integrated perspective on the interaction of demand and supply, our mission is to promote system efficiency, encourage innovation and diversity, empower energy consumers, and drive the decarbonisation of the energy sector.

For further information please visit:
www.smarten.eu

ABOUT DNV

DNV is an independent assurance and risk management provider, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry standards, and inspires and invents solutions.

We provide assurance to the entire energy value chain through our advisory, monitoring, verification, and certification services. As the world's leading resource of independent energy experts and technical advisors, we help industries and governments to navigate the many complex, interrelated transitions taking place globally and regionally, in the energy industry. We are committed to realizing the goals of the Paris Agreement, and support our customers to transition faster to a deeply decarbonized energy system.

For further information please visit:
www.dnv.com

Demand-side flexibility in the EU: Quantification of benefits in 2030, September 2022

AUTHORS:
Project Manager: Aurora Sáez Armenteros, *Senior consultant* (DNV)
Quality Assurance: Hans de Heer, *Principal consultant* (DNV)
Authoring team: Laura Fiorini, *Consultant* (DNV), María Miranda Castillo, *Consultant* (DNV), Thijs Slot, *Senior Consultant* (DNV)

PROJECT MANAGEMENT AT SMARTEN:
Andrés Pinto-Bello Gómez, *Head of Research and Projects* (smartEn)

smartEn and DNV would like to thank *smartEn* members for their invaluable contributions and feedback that made this report possible. In addition we thank *Solarpower Europe* for their cooperation facilitating accurate datasets on the solar PV industry.

DESIGN:
Think Things Studio Barcelona

Executive Members

APPLiA Home Appliance Europe, bne Association of Energy Market Innovators, centrica Business Solutions, dcbel, EATON Powering Business Worldwide, EDF, enel x

Entelios A part of Agder Energi, entra Agregación y Flexibilidad, epq, KNAUF ENERGY solutions, NODES, openADR Alliance, Schneider Electric

SIEMENS Ingenuity for life, tiko, The Traxis Group, vaasaETT, Voltalis

Regular Members

AFRY ÅF PÖYRY, ampx, AMPECO, AutoGrid, bamboo energy, BECHAINED, CATAPULT Energy Systems

chargepoint, cleanwatts, CUCULUS, CYBERGRID, DNV, Elli, Energy Pool Smart energy management

epexspot, EVBOX, FLEXCITY by Veolia, Fronius, geo, GS_y GridSingularity

HIVE POWER, Honeywell, i-EM Intelligence in Energy Management, IKEA / INGKA, Microsoft, The Mobility House

NET2GRID, NUVVE, octopus energy, piclo, Powerledger, sense

sonnen, sympower, TESLA, VIESSMANN, WATTSDAT, Wirepas

Associate Members

ade, DELTA Energy & Environment, EVN, Flexible Power Alliance Network, GridIO, gridX, JOULE ASSETS, next

REGALGRID sharing your power, ThermoVault, vgc Vanguard Consulting Oy, Vestas, VIOTAS, voltus Better Energy · More Cash


2030

Table of contents

EXECUTIVE SUMMARY

As the EU shifts away from the traditional energy system and heads towards a decentralised, digitalised and decarbonised transition, new and smart solutions are required to manage the ever-increasing variable generation mix whilst maintaining affordability and security of supply. Demand-side flexibility (DSF), the ability of customers to change their consumption and generation patterns based on external signals, is a crucial element in achieving these goals.

With the current geopolitical events causing skyrocketing energy prices and supply risk disruptions, the need to empower end-users to play an active part in securing and decarbonising the EU energy system is gaining traction in EU strategies and policies. However, the activation of consumers' flexibility still faces regulatory barriers, notably due to the delayed implementation by Member States of the Electricity Market Design. Furthermore, DSF still lacks visibility as a reliable, efficient and climate-friendly solution because its potential has never been systematically quantified. This results in DSF being a frequently overlooked solution in policy decisions, hindering its potential in accelerating the cost-efficient clean energy transition.

In order to fill this gap, smartEn – Smart Energy Europe, commissioned an expert study from DNV to quantify the potential benefits of a full deployment of DSF in the EU by 2030. This DNV study intends to inform policy decisions on how to achieve a 55% GHG reduction by 2030 in a cost-efficient way for both the whole energy system and consumers.

In a full-DSF activation scenario that unleashes the flexibility from buildings, electric vehicles and industry, the following results are found:

Wholesale benefits

In the year 2030 the model estimates a total of 164 GW upward flexible power[1] and 130 GW of downward flexible power[2]. With an activation of 397 terawatt hours (TWh) of upward DSF and 340.5 TWh of downward DSF the following results are found:

- **€4.6 billion (5%)** are saved due to lower costs to generate electricity compared to a scenario without DSF.
- The power system could serve all demand all year long, saving **€9 billion** on 'lost load' not served by the available generation.
- Renewable energy curtailment would be **15.5 TWh (61%)** less, improving the economics of renewables and the availability of decarbonized electricity to consumers.
- **37.5 million tonnes (Mt)** would be saved in annual GHG emission – i.e., 8%, nearly 84 kilos per capita, meaning that the power sector could exceed the '55% by 2030' target.

Benefits for security of supply

- The modelling suggests that the energy system in 2030 would lack at least **60 GW** of generation capacity to ensure security of supply during the highest demand peaks. Load shifting and load curtailment would allow the system to maintain security of supply by fulfilling the lack of generation capacity.
- Enabling 60 GW of DSF would save **€2.7 billion** annually compared to installing 60 GW of peak generation capacity.
- Activating DSF technologies in European balancing markets in 2030 could save a total of **€262–690 million** across the EU27, a balancing energy cost saving of **43% to 66%.**

1. Upward DSF means increase of generation or decrease of demand.
2. Downward DSF means decrease of generation or increase of demand.

Benefits for the distribution grid

- **€11.1–29.1 billion** would be saved in investment needs at EU 27 annually between 2023 and 2030. This represents between **27% to 80%** of today's forecasted investment needs (between €253.1 billion and €282.5 billion between 2023 and 2030 in investments in low- and medium voltage distribution grids to integrate new loads and RES capacity).

Benefits for consumers

The full deployment of DSF will translate into direct benefits for consumers with flexible assets, as well as indirect benefits to all customers through cheaper electricity prices and lower grid costs:

- Direct benefits could lead to a potential cost reduction for consumers of more than **€71 billion (64%)** per year on electric consumption.

- Over **€300 billion** in indirect annual benefits to people, communities, and businesses would result from reductions in energy prices as a whole, generation capacity costs, investment needs for grid infrastructure, system balancing costs, and carbon emissions.

This DNV study is a timely addition to the growing, but still limited, corpus of detailed research into the potential benefits of DSF to achieve the ultimate goals of providing secure, accessible supplies of affordable clean energy to all consumers in the EU27. The findings serve as a clear warning to not undervalue DSF given its huge potential impact toward an efficient, clean electricity system.

What is Demand-side flexibility? – the smartEn definition

"Demand-side flexibility" means the capability of any active customer to react to external signals and adjust their energy generation and consumption in a dynamic time-dependent way, individually as well as through aggregation.

Demand-side flexibility can be provided by smart decentralised energy resources, including demand management, energy storage, and distributed renewable generation to support a more reliable, sustainable and efficient energy system.

Modelling and scenario-building

The input data and assumptions in the wholesale market simulation model are based largely on the Fit for 55 objectives and REPowerEU. Drawing on these, DNV has defined inputs – divided into generation mix, electricity demand, DSF technologies and CO2 emission target. DNV's complex model assesses monetary values of system-level savings and end-user benefits on the wholesale market from a full activation of DSF.

The study explores two scenarios, 'DSF' and 'no-DSF', the latter providing a reference against which to compare costs, benefits, emissions, and other outputs. Both have the same amount of flexible assets, but in the DSF scenario these assets are fully price-elastic. In the no-DSF scenario, distributed flexible assets are fully price-inelastic, though larger assets (electrolysers, front-of-meter batteries and central generators) are fully price-elastic in both scenarios.

The estimated total benefit represents an order-of-magnitude value for the opportunity that could be lost by failing to activate this level of flexibility.

DNV has performed calculations outside the model, using literature and simplified methodologies, to estimate DSF benefits for adequacy, balancing and grid infrastructure costs.

CONSIDERATIONS:

- The model developed and applied for this study, and its results, are constrained by limitations of data quality, comparability, and availability across Member States in the EU 27.

- DNV also points to a lack of studies on the quantification of infrastructural benefits of DSF, suggesting that this is a signal for relevant stakeholders to further investigate the topic.

- The no-DSF scenario is an unrealistic one given that flexibility is already activated to varying degrees in several EU member states. The DNV study explains in detail how this scenario has been carefully constructed to allow a meaningful quantification of the potential value of DSF to the energy system.

- The model is an energy-only one, based on marginal costs, in line with the current market functioning. The model does not consider capital expenditure costs for generation assets, batteries, electrolysers or DSF, except for the quantification of the security-of-supply benefits.

- Although DSF investments are substantially lower than the other technologies mentioned, it is unclear how much the full potential will develop on its own – assuming all regulatory barriers are removed – or whether additional incentives are needed, as we have seen and continue to see for batteries, electrolysers, and renewables.

- The model did not take into account the positive energy efficiency impact of DSF activations, nor potential savings in TSO redispatch costs and TSO grid reinforcement costs.

- Benefits within the four segments (wholesale, adequacy, balancing and distribution grids) have been calculated separately. The total DSF benefits are lower than the sum of the benefits per segment, due to the close interaction of these four segments.

- Gas prices considered in the model are moderate compared to the exceptional 2022 levels.

1. INTRODUCTION

The use of Demand-Side Flexibility (DSF) in our European power system has been advocated for many years as a crucial tool that empowers consumers to help integrate renewable energy sources in the energy system, and to increase the overall efficiency of system development and day-to-day operations. More DSF deployment should result in having more flexibility in the system at times of peak electricity demand, thereby reducing the need for more expensive sources of power generation to remain available and be dispatched and thus reducing the overall prices to consumers. Additionally, DSF could help to reduce the need for power grid investments, since the availability and deployment of more flexibility on the demand side can help to reduce strain on critical components and/or connections in the grid. This is especially so in light of the fundamental system change in which fully controllable, fossil-based power plants are rapidly being replaced by renewable energy sources, whose production is largely determined by weather conditions.

Consumers, however, largely consider electricity to be a commodity that they consume whenever they need it. Being more flexible in the way they consume their power is typically not something they are concerned about, largely because most consumers pay a fixed price per kilowatt-hour (kWh) to their retail supplier.

To advance insights on what DSF can mean for the (transition of the) European power system, smartEn commissioned a study from DNV, aimed at quantitatively assessing the potential benefits of a full deployment of DSF in the EU 27 Member States by the year 2030.

1.1. Context

Although DSF has been earmarked as an important source of power system flexibility, its actual contribution to current system operations and the power market remains largely unknown. Even though EU directives and regulations aim to stimulate a more widespread adoption and market participation, overall contributions (responding to system needs that are reflected through market prices) appear to remain limited. Ahead of this study into EU-wide benefits, there are no (public) sources available that have investigated overall availability, deployment and/or pricing of DSF across EU 27 nations. Some of the available publications provide more detailed insight into the possible contributions of specific forms of demand response, benefits for specific countries, or contributions to cost savings in specific areas (e.g. grids in a specific country).

In the context of the Fit for 55 package and the associated efforts that Member States are undertaking to achieve 55% greenhouse gas (GHG) emission reductions by 2030, DSF may have a key role in providing the flexibility needed to allow for this objective to become a reality. In addition, recent events such as the war in Ukraine, and aggravated climate concerns, are driving a (much) quicker phase-out of the use of (Russian) gas and a ramp-up of emission reduction targets. These updated goals are incorporated into the European Commission's REPowerEU Communication and the emergency electricity market design interventions.[3] These updated strategies also include a vast expansion of distributed flexible assets and requirements for their activation, intended to be able to serve even more of Europe's energy needs with renewably generated power.

3. See: REPowerEU: affordable, secure and sustainable energy for Europe | European Commission (europa.eu)

1.2. Purpose of this study

The purpose of this study is to assess the potential benefits of DSF to the European power system in the year 2030, where all renewable energy sources (RES) targets and 55% GHG reduction are achieved, assuming that DSF can access all markets throughout the EU 27. The project team has developed and executed an approach to be able to identify:

- **The DSF capacities that can be available in 2030**
- **The DSF volumes that would be utilised to optimise the wholesale market in 2030**
- **The potential impact that DSF activations have on wholesale, adequacy, system balancing and grid infrastructure**
- **How system-wide DSF benefits translate into benefits for consumers**

Although the study addresses all areas – wholesale market, system balancing, and infrastructure – the focus of the approach and modelling is on wholesale because the potential impact was foreseen to be much larger. Throughout the study, 'wholesale' is defined as forward, day-ahead and intraday electricity markets (explicitly excluding balancing markets / ancillary services).

1.3. Approach

Specific industry insights about technology developments and policy targets are combined with those from available public sources on the availability and impacts of DSF-technologies, such as reports by Eurelectric, ENTSO-E and individual TSOs such as RTE (France), Elia (Belgium), E-Bridge and DNV. These inputs and datasets, and contributions by smartEn members, made up the inputs for this study.

Electricity wholesale market benefits are assessed by using these (additional) DSF options as input to wholesale market simulations in a 'DSF scenario' for 2030 in DNVs European Market Model, an economic dispatch simulation model to simulate power markets. Results are compared against a 'no-DSF scenario' that assumes no flexibility to be available from the DSF-technologies whose impacts are assessed in this report (see 2.3.1 for a list of the selected DSF technologies). This comparison shows differences between the two scenarios in terms of reaching emission reduction targets and the costs for generation and consumption. It should be noted that the no-DSF scenario is not realistic and is not a counterfactual, but rather a reference to calculate the maximum achievable potential.

Benefits for the balancing market and grid development are approximated based upon deductions from various sources, e.g. departing from specific grid savings in a single Member State. Although this may be assessed in much more detail later (e.g. by assessing the specific grid situation and challenges to overcome in each Member State and at every grid level), the project team expected benefits in wholesale trading and adequacy to be much larger due to sheer trading volumes across all EU 27 Member States. Therefore, a thorough analysis has first been performed on these two aspects.

Further details about our approach and its limitations are provided in chapter 2 and Appendix A.

1.4. Structure of this report

Chapter 2 provides further details of the approach regarding wholesale market simulations in two different scenarios (DSF and no-DSF). Chapter 3 discusses the results of the market simulations regarding the different DSF-technologies. Overall benefits in terms of wholesale benefits, emission reductions, generation adequacy, balancing and grid development across the EU 27 are the focus of chapter 4. Chapter 5 assesses the resulting consumer benefits. Finally, chapter 6 provides an overview of DNVs main conclusions and recommendations.

Appendix A provides further detail about the approaches to quantify the impacts of DSF in the various areas (wholesale, balancing and grid development).

2. INPUT AND SET-UP OF THE MARKET MODEL

The main focus of this study is the analysis of the potential wholesale benefits of DSF use in the European power system in 2030. This focus was based on the assumption that, out of the four main value drivers (wholesale, adequacy, balancing and grid infrastructure), the first inhibits the highest potential for DSF to valorise – an assumption that is confirmed by the outcome of this study. To quantify these potential wholesale benefits of DSF use, DNV modelled the European power market considering the different DSF options available in 2030.

DNV has used its European Market Model, a fundamental market model that simulates the day-ahead spot price by optimising the unit commitment and economic dispatch of electricity generation. The simulations are performed on an hourly time-resolution containing a detailed representation of generation, commodity prices and demand for all bidding zones in EU 27 Member States, based on the following modelling assumptions:

- Generation capacities are modelled on an individual basis with detailed techno-economic characteristics such as, but not limited to, heat rates, ramping ability, minimum stable level, fuel cost, other variable operating costs, maintenance and forced outage rates, etc.

- Renewable generation takes volatility into account through the use of historical or re-analysed time series of, for example, data on wind speed and solar irradiation for different locations. These profiles take geographical correlation into account.

- Market exchanges between countries (i.e. bidding zones) are defined based on Net Transfer Capacities. The increase in available transmission capacity is based on available projections announced by individual TSOs and/or ENTSO-E. Transmission and distribution constraints within bidding zones are not modelled.

- The demand consists of an hourly fixed demand profile, flexible demand-side management components and other flexible load originated by front-of-the-meter applications such as utility-scale batteries. Flexible demand is optimised against certain constraints within the model (see Appendix A – section 1.1.2) – e.g. electric vehicles (EVs) need to be charged by a certain volume within a specified period (e.g. during the night or within one week).

- The model set-up assumes that all flexible demand and generation, both front and behind-the-meter, is exposed to the market.

- The commodity prices are set at a "normal' level excluding exceptional situations such the Ukrainian war as well as the low availability of the French nuclear portfolio.

- Network tariffs and taxation are not included in the model. As a consequence, there is no explicit optimisation of (collective) self-consumption. In practice, this effect is implicit to the system behaviour. For example, if a residential customer has both rooftop PV and a battery, then the battery (being exposed to market prices) will typically charge when high amounts of PV energy are produced – yielding a similar result as self-consumption optimisation.

Finally, the input data and assumptions included in the model are focused on the Fit for 55 objectives (European Commission , 2021) and REPowerEU Communication (European Commission, 2022). Considering these guidelines, DNV has defined the inputs to the European Market Model, which can be divided into generation mix, electricity demand, DSF technologies and carbon dioxide (CO2) emission target.

2.1. CO2 emission target

Fit for 55 establishes the target of reducing net GHG emissions for all Member States by at least 55% by 2030, compared with 1990 levels. DNV translated this target into the equivalent of 410 million tonnes (Mt) of CO_2 emissions in the EU power sector by 2030. This CO_2 emission target is based on the result of DNV's Energy Transition Outlook model (DNV, 2021). This target was used as a benchmark to evaluate the ability of the 2030 scenario, and DSF in particular, to help reach the Fit for 55 target.

2.2. Generation capacity mix

Considering the EU 27 Member States, the generation capacity mix in 2030 is characterised mainly by a high share of renewables, reaching 75% renewable installed capacity. Thermal installed capacity is reduced to less than 25% of the generation portfolio, as seen in Figure 1. Gas-fired generation is the main thermal source[4], while coal and lignite generation are significantly reduced. The development of generation installed capacities are in line with the targets presented in REPowerEU and Fit for 55 for an increase in renewable energy production, an increment of renewable hydrogen production, and a consequent decrease in GHG emissions. In particular, installed solar PV capacity (front and behind the meter) in EU 27 reaches 600 GW by 2030 as defined in the REPowerEU Plan. Moreover, offshore wind capacities in the North-Sea are increased based on the latest targets agreed by Belgium, Denmark, Germany and the Netherlands, reaching 65 GW by 2030 (BMWK, 2022).

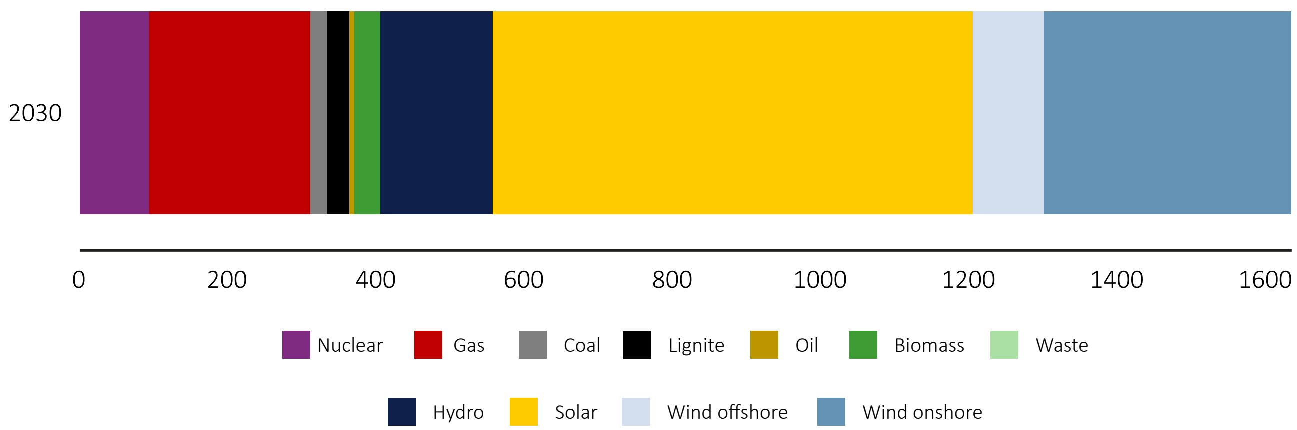


Figure 1 – Installed generation capacity EU 27 in 2030 (GW)

2.3. Electricity demand

The electricity demand is considered in the analysis by differentiating the traditional demand for electricity from the additional demand due to the electrification of passenger transport and heating, and from electrolysers for power-to-hydrogen conversion.

- **Traditional demand encompasses,** for example, household, commercial and industrial power demand, categories already considered nowadays. This segment of demand reaches 2858 TWh across EU 27 Member States in 2030.

- **Electrification of passenger transport**[5] is driven by support schemes and by technological and infrastructure developments and expected cost degression. This creates demand for 151 TWh of electricity in 2030.

4. Gas prices are assumed to decrease by 2030. The model considers a gas price of 25.3 €/MWhth in 2030.
5. In our model this is limited to passenger EVs.

- **Electrification of heating consists** of both space heating and industrial heating, accounting for 510 TWh by 2030.[6]

- **Power-to-hydrogen** entails the electricity demand required by electrolysers. The electrolysers' demand increases significantly in 2030 to reach the targeted 10 Mt of renewable hydrogen production in Europe, based on the REPowerEU Communication. Therefore, using European Commission assumptions and according to DNV calculations, 562 TWh of electricity consumption for hydrogen production is expected in 2030.[7]

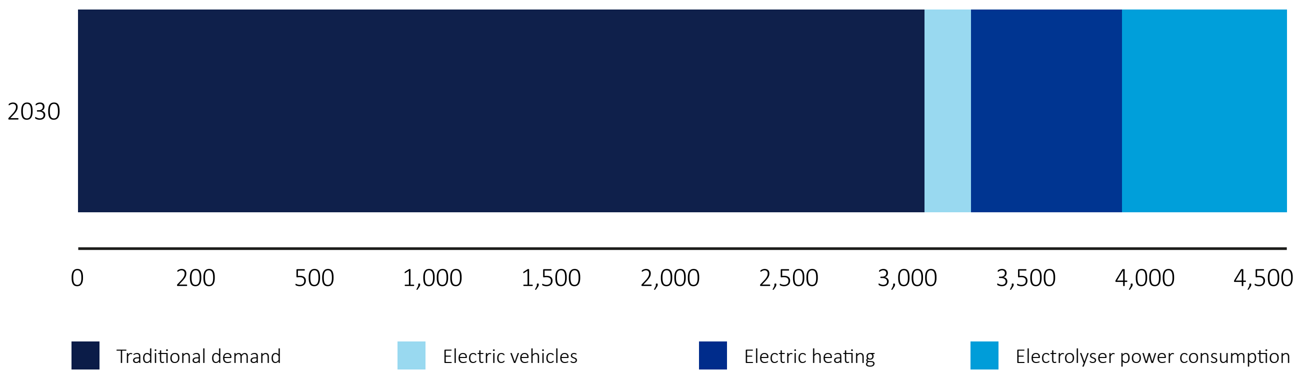


Figure 2 – Electricity demand EU 27 in 2030 (TWh)

2.3.1. DSF TECHNOLOGIES

To quantify the potential benefits of demand-side flexibility, DNV has modelled DSF technologies as part of the European power system used in the analysis. Based on the technology characteristics and high flexible power potential, DNV included the following DSF technologies:

- Smart charging
- Vehicle-to-grid
- Behind-the-meter (BTM) batteries
- Industrial demand-side response (DSR)
- Residential space electric heating
- Industrial electric heating
- District heating – combined heat and power (CHP)
- Industrial heating – CHP

Other DSF technologies with relevant potential were not included in the list for this study, due to unavailability of sufficient data to assess their availability throughout EU 27 by 2030. These include, for example, district cooling, residential cooling, Joule effect electric heating, and residential electric boilers. To mitigate the risk of overestimating total DSF capacities that are available to the power system in 2030, DNV has decided to not incorporate these technologies into the study.

Finally, behind-the-meter solar PV is also considered in the model. However, it is not modelled as a controllable asset but as non-curtailable PV generation.

7. European Commission assumptions are a utilisation factor of 43% and electrolyser efficiency of 70%.
6. Water heating is not included.

Smart charging and vehicle-to-grid

Electric vehicles are included in the analysis and considered as DSF technologies that can provide flexibility by shifting their load. Smart charging is modelled by optimising the total daily EV demand when EVs are connected to the grid. For a detailed description of smart-charging modelling and references refer to Appendix A – section 1.1.2.3.

A total of around 60 million EVs by 2030 are included for the 27 Member States.

Additionally, DNV assumed that 30% of the EV chargers are enabled for bidirectional charging (European Commission, Directorate-General for Energy, 2022). Bidirectional ch arging or vehicle-to-grid (V2G) enables the EV battery to feed in to the grid as well as charging. As such, V2G is modelled as behind-the-meter battery whose charging and discharging is limited by the EVs that are connected to the grid. For detailed description of V2G modelling and references refer to Appendix A – section 1.1.2.4.

Behind-the-meter batteries

BTM batteries provide flexibility through charging and discharging daily when prices show a sufficient spread to cover their efficiency and operational costs. For detailed description of Battery Energy Storage System (BESS) modelling and references refer to Appendix A - section 1.1.2.2. In this study, DNV has considered a total of 10.9 GW of BTM batteries in the EU 27.

Industrial demand-side response

Industrial DSR is considered a curtailable load. The load would curtail above a given electricity price that varies per category and is based on the cost that the industrial plant would incur when interrupting its operation. For detailed description of industrial DSR modelling and references refer to Appendix A – section 1.1.2.1. A total of 21.7 GW of industrial DSR capacity is included across all Member States.

Residential electric heating

In the model, all flexible residential electric heating is assumed to be provided by heat pumps and is considered a shiftable load within 12-hour periods. Therefore, the half-daily load required for residential electric heating is met, but the hours when the consumption take place can shift overtime. For detailed description of residential electric heating modelling and references refer to Appendix A – section 1.1.2.5. In order to represent this load, DNV has considered a total space heating electricity demand of 449 TWh by 2030.

Industrial electric heating[8]

Industrial electric heating (e-boilers) is considered a curtailable load. The load would curtail above a given electricity price based on the cost that the industrial plant would incur when switching off the e-boiler. For detailed description of industrial electric heating modelling and references refer to Appendix A – section 1.1.2.6. DNV has considered 7 GW of industrial heating load across all Member States.

District heating – CHP

District heating – CHP is considered as aggregated CHP plants with a daily generation requirement. This DSF technology behaves as a generator that can always deviate upwards from their daily generation requirement, but can only deviate downwards when it is more optimal to pay a penalty than to generate (the penalty price is based on the alternative cost for heating). For detailed description of CHP modelling and references refer to Appendix A – section 1.1.2.8. DNV has included a total of 56 GW of CHP district heating capacity in EU 27 by 2030.

Industrial heating – CHP

Industrial heating – CHP is represented as CHP plants with specific daily generation requirements. This technology is modelled following the same logic as district heating – CHP, with different generation requirements and penalties. For detailed description of CHP modelling and references refer to Appendix A – section 1.1.2.7. DNV has included a total of 19 GW of industrial CHP capacity by 2030.

8. This category is limited to heating by e-boilers due to data unavailability at European level on other technologies such as heat pumps.

2.3.2. OTHER FLEXIBLE TECHNOLOGIES

The following technologies are included in the model as flexible technologies but are not considered as demand-side flexibility because they are not placed behind the meter. The flexibility that these technologies provide is therefore not included in the DSF capacities and their possible benefits that this study sets out to quantify. At the same time, since these technologies are actively participating in the electricity market, they do influence the outcome of this study.

Grid-connected storage

Grid-connected batteries provide flexibility through charging and discharging daily when prices show a sufficient spread to cover their efficiency and operational costs. For detailed description of BESS modelling and references refer to Appendix A – section 1.1.2.2. In this study, DNV has considered a total of 15.5 GW of front-of-the meter batteries in EU 27.

Electrolysers

Electrolyser consumption is considered as a flexible load. The load would curtail above a given electricity price based on the cost of hydrogen, this is estimated at 86.2 €/MWh. For detailed description of electrolyser modelling and references refer to Appendix A – section 1.1.2.9. Installed capacities and annual consumptions are based on the REPowerEU Communication's indicative targets of 10 mt renewable hydrogen annual production, which may translate to up to 149 GW in total for all Member States by 2030.[9]

2.4. Reference scenario (no-DSF)

To evaluate the outcomes of the model and derive the potential DSF contribution, it is necessary to set a reference against to which to compare costs, emissions, and other parameters.

Lack of data on the DSF utilised today, and on DSF utilisation prospects towards 2030, makes it impossible to quantify the counterfactual system costs. Therefore, DNV modelled a 2030 scenario in which the demand side is not flexible. Realising that demand-side technologies are to some extent – and in some Members States more than others – already actively participating in the electricity market, DNV acknowledges that the reference scenario is not a realistic one. The main purpose is to quantify the total potential benefit of DSF for the considered technologies. If there are still certain barriers in 2030 to DSF responding to external price signals, a certain share of this potential will not be achieved. The total benefit provides an order-of-magnitude value of this missed opportunity (albeit an upper bound).

The no-DSF scenario considers the same amount of DSF technologies (e.g. the same amount of EVs), yet all DSF technologies have a fixed demand/generation profile and therefore show no price responsiveness – i.e. they provide no flexibility to the system.

The no-DSF scenario does include the same amount of other flexibility sources that are not considered to be DSF, mainly electrolysers and front-of-the-meter storage. These flexible resources are price responsive and are treated as such in the no-DSF scenario.

Throughout the report the reference scenario in which DSF technologies are not flexible is referred to as the 'no-DSF' scenario; and the scenario in which DSF technologies are flexible is referred as the 'DSF scenario'.
The table 2.1 provides a summary of the implementation of the DSF and no-DSF scenarios. The detailed description of the modelling of both scenarios is included in Appendix A – section 1.1.2.

9. This capacity value was calculated based on the targeted renewable hydrogen production in REPowerEU and its reported assumptions.

Table 2.1 – DSF and no-DSF scenario implementation

	DSF scenario	No-DSF scenario
Industrial DSR	Industrial DSR capacity is price responsive	There is no industrial DSR capacity, all is modelled as fixed traditional load
BESS – behind the meter	BESS capacity provides flexibility	BESS systems behind the meter do not feed-in or off-take electricity.
Smart charging	EV charging is optimised against prices	EV charges following a fixed hourly profile
V2G	V2G capacity provides flexibility	There is no V2G
Residential electric heating	Residential electric heating is optimised against prices	Electric heating demand follows a fixed hourly profile
Industrial electric heating – CHP	CHPs can increase/decrease generation to provide flexibility	CHPs follow a fixed generation profile
District heating – CHP	CHPs can increase/decrease generation to provide flexibility	CHPs follow a fixed generation profile
BESS – front of the meter	BESS capacity provides flexibility	BESS capacity provides flexibility
Electrolysers	Electrolysers are price responsive, i.e. flexible	Electrolysers are price responsive, i.e. flexible

3. DEMAND-SIDE FLEXIBILITY PROVIDED IN 2030

This section presents the results on quantification of DSF in 2030, based on wholesale optimisation. First, the total flexible power and activated flexibility is reported at EU 27 level. Then, the modelling of flexibility and its quantification approach is detailed per technology.

3.1. DSF available power and activated flexibility

DSF available power

Based on the inputs and outputs of the market model, there is a total of 164 GW upward flexible power and 130 GW of downward flexible power in 2030. Considering 752 GW of peak demand of the EU 27 system in 2030, the upward and downward flexible power represents about 22% and 17% of the peak demand, respectively.

Table 3.1 summarises the available flexible power per technology, on average in 2030. It shows both upward flexibility (increasing generation or reducing demand) and downward flexibility (decreasing generation or increasing demand).

It should be noted that the way the flexible power is calculated varies per technology. This is because the technologies are flexible in different ways, e.g. smart charging available power is not constant but depends on the number of cars connected to chargers that have available battery capacity.

Table 3.1 – Available flexible power

Technology	Upward flexible power [MW]	Downward flexible power [MW]
Industrial DSR	21,731	0
BESS Behind the meter	10,850	10,850
Smart charging	48,704	16,295
V2G	25,594	25,594
Residential electric heating	32,841	73,385
Industrial electric heating	7,082	0
Industrial heating – CHP	6,355	482
District heating – CHP	10,581	3,500
Total	**163,738**	**130,106**

Activated flexibility

DNV calculated the amount of flexibility that was activated as a result of the 2030 electricity (wholesale) market simulation that optimises the system behaviour. The results indicate that a total of 397 TWh and 340 TWh of upward flexibility and downward flexibility, respectively, are activated in 2030 within EU 27. Considering 4,081 TWh of total demand in 2030, the upward and downward activated flexibility corresponds to about 10% and 8% of the total demand, respectively.

Table 3.2 summarises the total activated flexibility broken down per DSF technology. **The results show that the largest part of activated flexibility in both directions is supplied by residential electric heating, followed by EVs, CHPs supplying district heating, and V2G.**

Table 3.2 – Total activated flexibility

Technology	Upward flexibility [GWh]	Downward flexibility [GWh]
Industrial DSR	1,071	-
BESS Behind the meter	637	871
Smart charging	106,286	106,266
V2G	21,009	23,764
Residential electric heating	195,532	195,532
Industrial electric heating	141	-
Industrial heating – CHP	12,697	12
District heating – CHP	59,601	14,032
Total	**396,974**	**340,477**

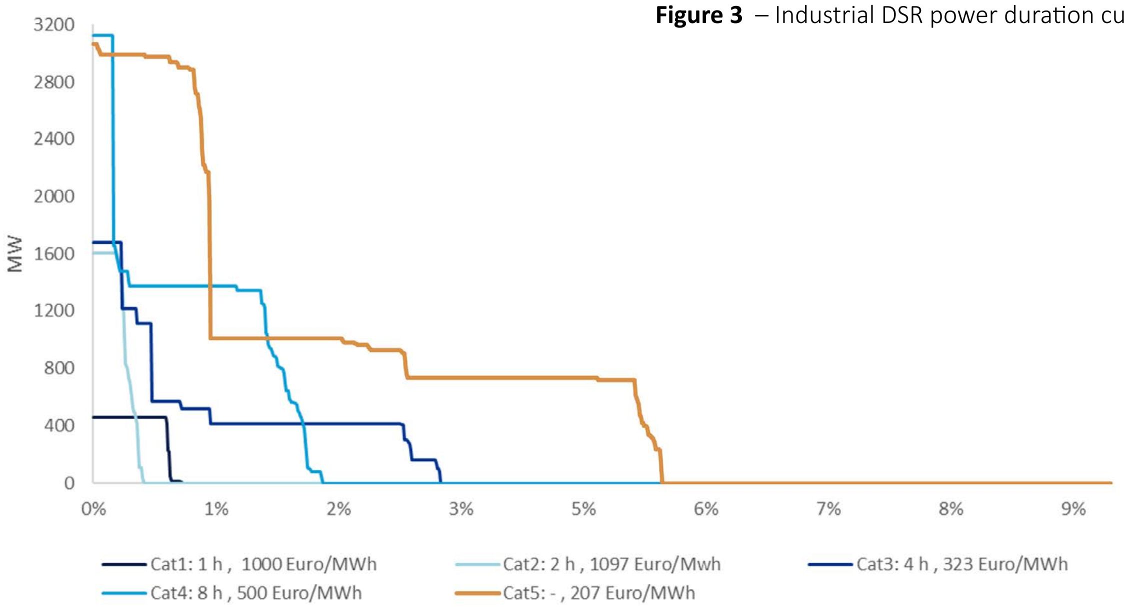
The next subsections include a more detailed description of the model results and the calculation of flexible power and activated flexibility per technology.

3.2. Industrial DSR

All energy generated by industrial DSR assets is considered upward flexibility as it corresponds to a reduction in demand. When the entire cheaper generation capacity is already fully committed, industrial DSR acts as a last resort to prevent unserved load. The results of the model show that the average price of activated industrial DSR is below 550 €/MWh in all Member States except in two Member States, where more expensive categories are also activated sometimes.

To illustrate the realised capacity provided by industrial DSR, the load duration curve of industrial DSR activation is included below (Figure 3). The load duration curve shows the duration (% of the hours in a year; x-axis) of deployment of a certain load level (MW; y-axis) throughout all the 8,760 hours of 2030. It can be observed that the cheapest industrial DSR option (i.e. 207 €/MWh) is the most frequently activated, about 500 hours in one year for the whole EU 27, whereas the most expensive category (i.e. 1,097 €/MWh) is activated for less than 1% of the time. Overall, the total activated upward flexibility is 1,071 GWh.

Figure 3 – Industrial DSR power duration curve



3.3. BESS – Behind the meter

All energy either supplied or consumed by behind-the-meter batteries is considered upward or downward flexibility, respectively. The total activated upward flexibility is 637 GWh, whereas the total activated downward flexibility is 871 GWh. The difference between upward and downward flexibility is due to charging and discharging inefficiencies.

For this technology, the flexible power is calculated the installed capacity. This capacity is available in both directions, charge and discharge.

One can see in Figure 4 an illustrative example of the operation of behind-the-meter BESS in one week of 2030 in Germany. The batteries follow the market price: when the price variations are large enough to overcome operating inefficiencies and costs, the batteries charge if the price has dropped, or discharge if the price has increased. Note that this optimisation is done for one day look-ahead, therefore sufficient price spread need to be fulfilled during the same day.

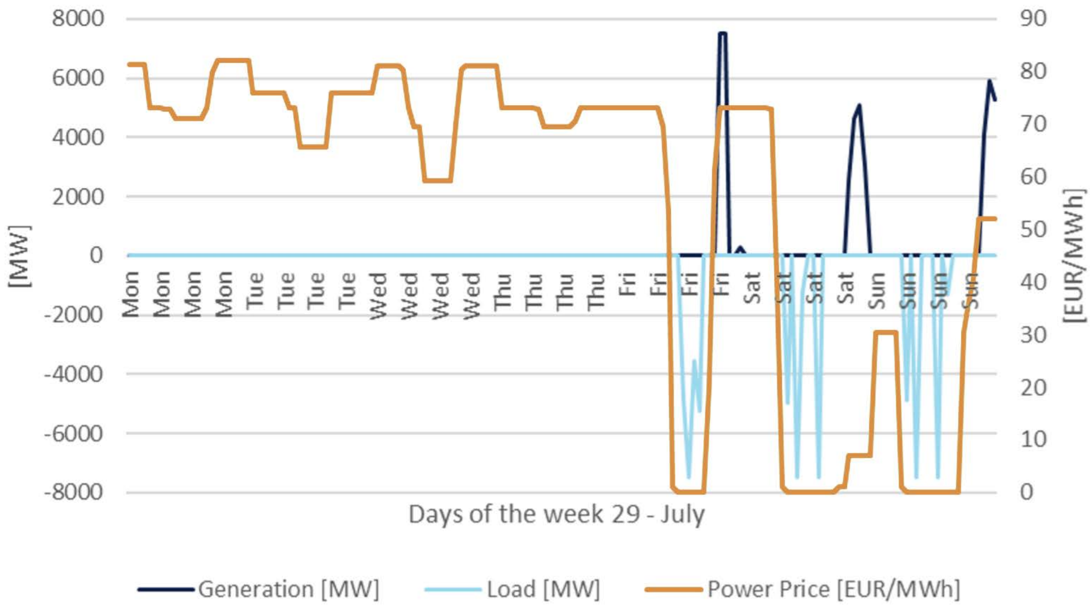


Figure 4 – Example of behind-the-meter BESS (dis)charging during week 29 in Germany in 2030

3.4. Smart charging

The flexibility provided by EVs is calculated as the difference between the optimised EV load given by the simulation results and a fixed EV charging profile used as reference in the no-DSF scenario, while respecting the total daily load requirement. Upward flexibility is provided when the optimised EV load is below the reference charging profile, whereas downward flexibility is provided when the optimised EV load is above the reference charging profile. As such, the upward and downward flexible power is calculated as the average deviation from the reference charging profile respectively.

To show the difference between the optimised smart charging and a non-flexible EV charging behaviour, Figure 5 includes the resulting profile from the market model against the non-flexible EV profile. The results correspond to EVs during week 4 of 2030 in Spain.

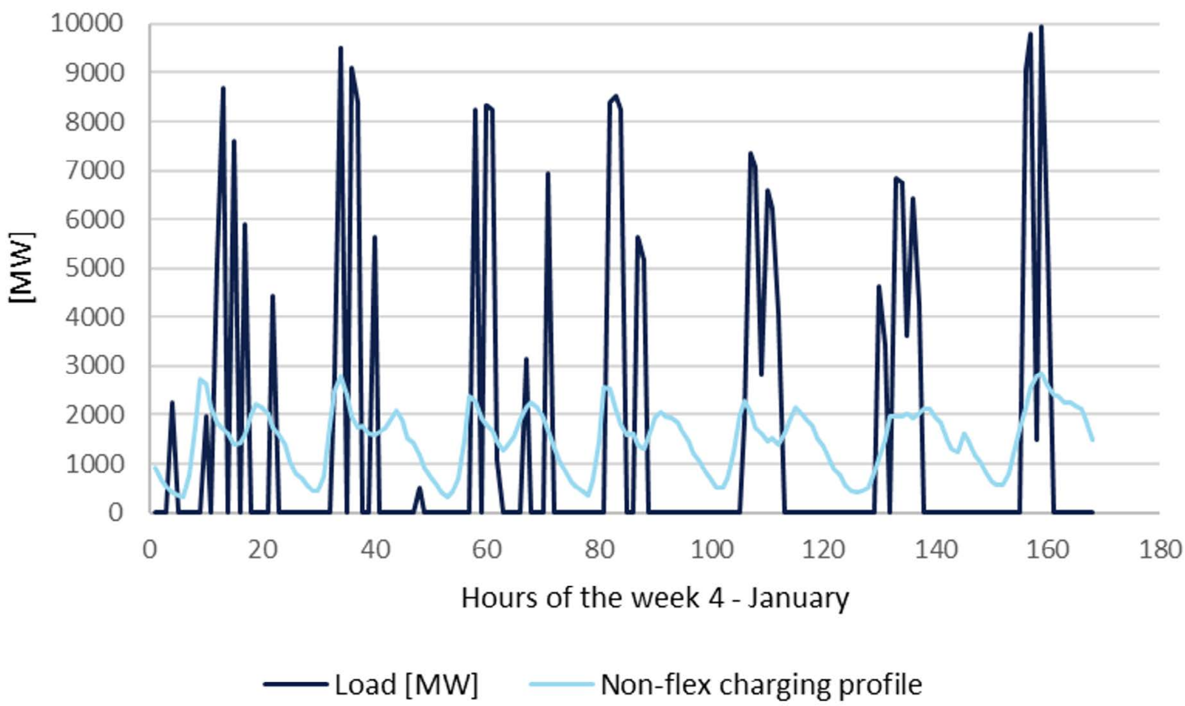


Figure 5 – Comparison between optimised EV charging and reference EV charging profile of Spanish EVs during week 4 of 2030

Downward activated flexibility absolute values are the same as the EV daily consumption per Member State is a given input to the optimisation challenge. Overall, the total activated flexibility is 106.3 TWh in both directions.

Figure 6 illustrates an example of the behaviour of EVs in week 30 in Spain resulting from the market model. The figure shows how the daily EV load is optimised against market prices while respecting the EV capacity available each hour. As the daily EV fleet consumption is a required input of the model, the EVs charge every day, preferably during hours of low prices. Additionally, the hourly maximum charging power is capped by the availability profile, which is defined as the hourly charging capacity connected at private and office charging points.

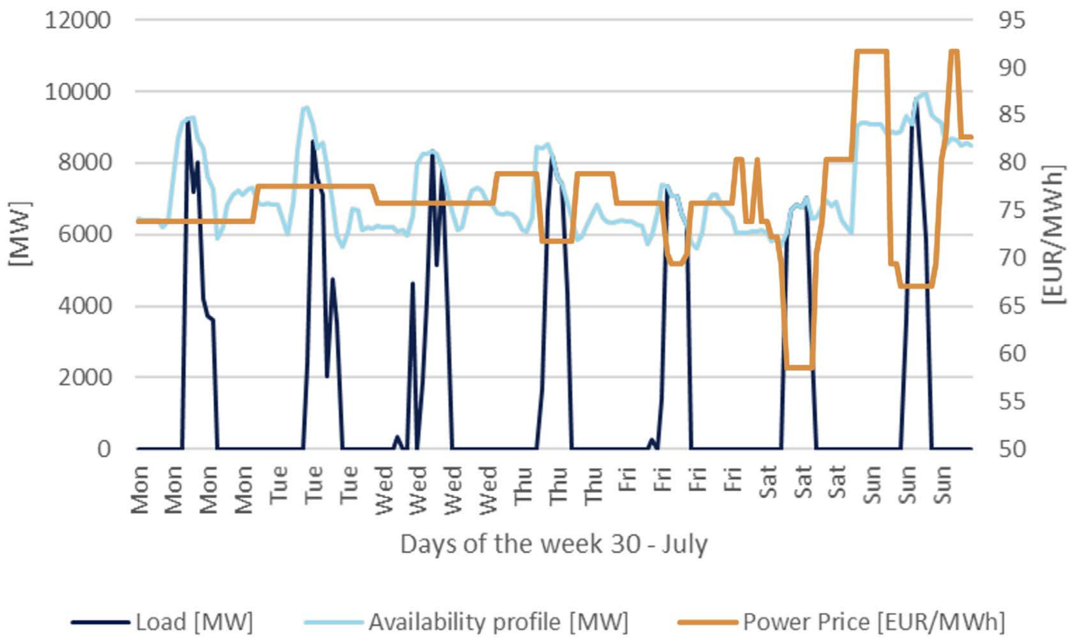


Figure 6 – Example of EVs charging in Spain during week 30 of 2030

3.5. V2G

All energy either supplied or consumed by the EVs via V2G is considered upward or downward flexibility, respectively. For this technology, the flexible power corresponds to the total charging point capacity with V2G capability (i.e. 30%) multiplied by the average utilisation factor (26.1%). Overall, the total upward flexibility is 21 TWh and the total downward flexibility is 23.7 TWh. Load values are 12% higher due to charging/discharging inefficiencies.

One can see an illustrative example of the behaviour of V2G in a week in the Netherlands in 2030 in Figure 7. V2G follows the market prices: when the price variations are large enough to overcome operating inefficiencies and costs, the batteries charge if the price has dropped, or discharge if the price has increased, keeping the number of daily cycles below or equal to 2. Additionally, the max charge or discharge power is constrained by the availability profile (both consumption and feed-in) of charging points, as shown in Figure 8.

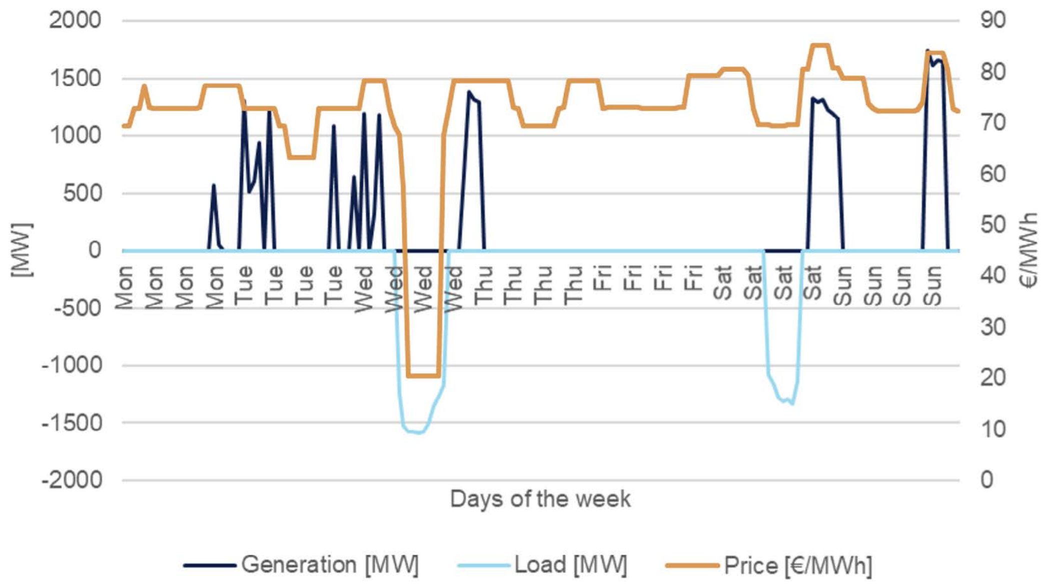


Figure 7 – Example of V2G behaviour in the Netherlands during a week of 2030

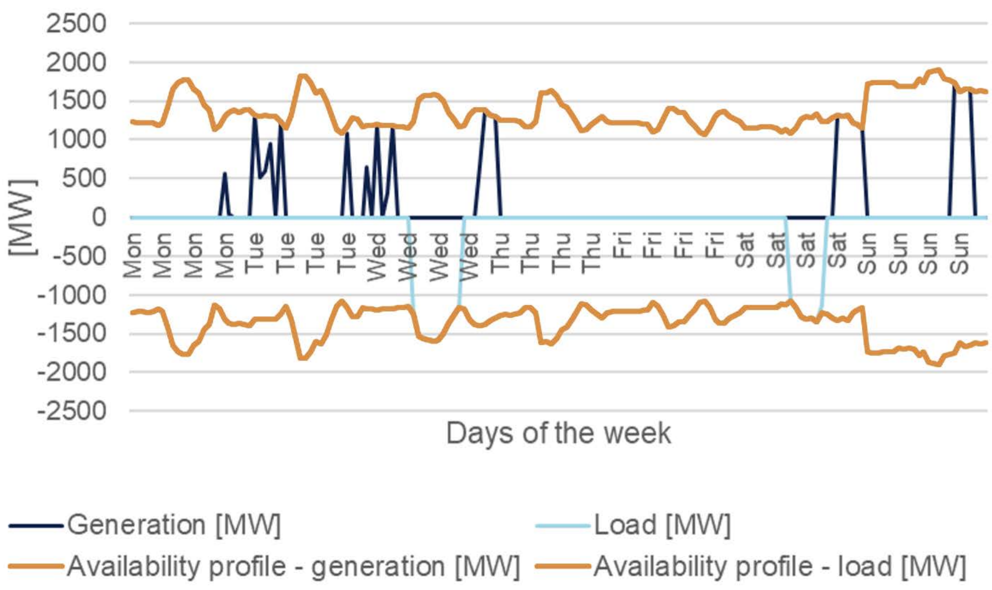


Figure 8 – Example of V2G behaviour in the Netherlands in the 2030 DSF scenario within feed-in and load availability profiles

3.6. Residential electric heating

The flexibility provided by residential electric heating is defined as the difference between the optimised load given by the simulation results and the hourly profile used as reference in the no-DSF scenario. Upward flexibility is provided when the optimised load is below the reference profile, whereas downward flexibility is provided when the optimised load is above the reference profile. As such, the upward and downward flexible power is determined by the average respective deviation from the reference hourly profile.

An Illustrative comparison between the 'optimised' load and the reference profile of German residential electric heating during week 11 of 2030 in the DSF scenario is shown in Figure 9. One can see that the load is preferably supplied in hours with low power prices, while fulfilling the 12-hour consumption requirement.

For all EU 27, the total activated flexibility is 195.5 TWh in both directions.

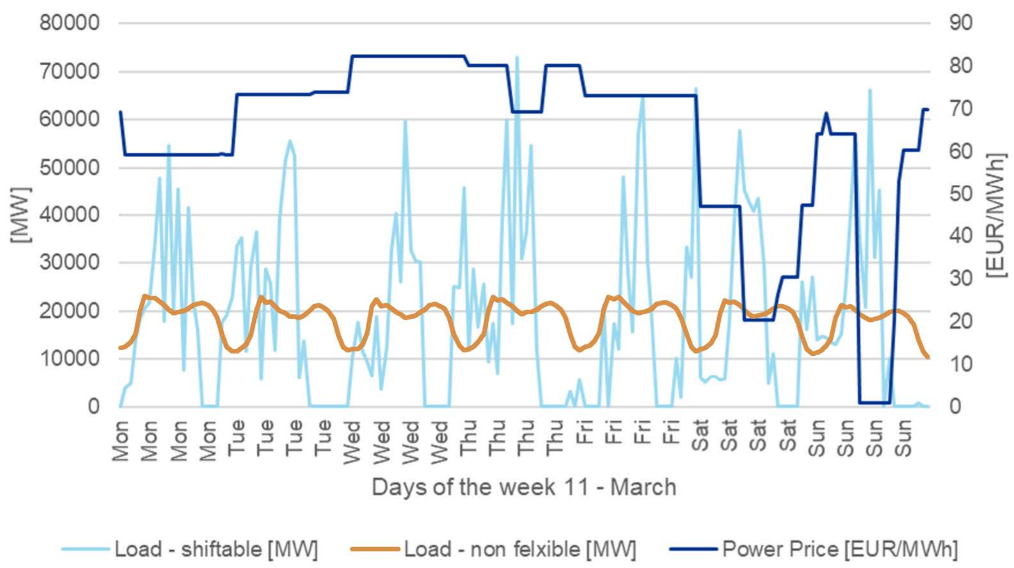


Figure 9 – Example of residential electric heating in Germany during week 11 of 2030

Several studies show that demand response, when applied to (residential) electric heating, also leads to energy efficiency; the total energy used will be lower than the counterfactual (no DSF). This is an important upside, as it leads to direct customer savings, lower demand (thus lower market prices), and carbon savings. The main reason for not including this in our market modelling and quantification is the lack of empirical data that is both relevant for the technology considered (heat pump) and representative for EU 27.

3.7. Industrial electric heating

The flexibility provided by industrial electric heating is determined by the difference between the non-flexible industrial electric heating demand (fixed) profile and the optimised demand profile given by the simulation results. Upward flexibility is therefore provided when the optimised demand is below the constant non-flexible profile. As such, the upward flexible power is calculated as the total installed capacity of flexible industrial load.

An illustrative comparison between the optimised load and the reference profile of Finnish industrial electric heating during week 1 of 2030 is shown in Figure 10. One can see that the load is curtailed when the power price rises above 500 €/MWh.

Overall, the total activated upward flexibility for EU 27 in 2030 is 140.7 GWh.

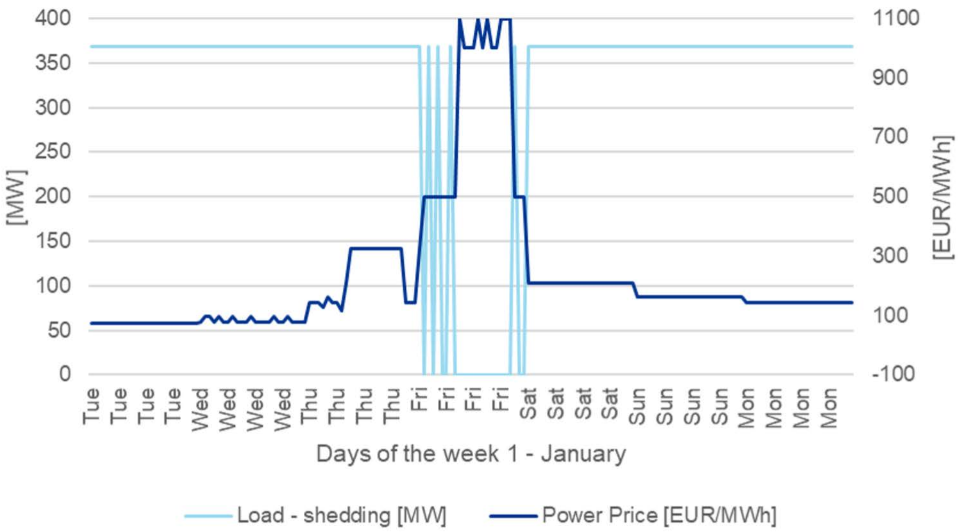


Figure 10 – Example of industrial electric heating behaviour in Finland in week 1 of 2030

3.8. Industrial heating – CHP

Industrial heating – CHP is modelled as a CHP plant with a power generation profile set at 100% of max capacity between 05:00 and 20:00 hours, and at 65% otherwise. Upward flexibility is, therefore, provided when the generation is above the hourly target production, whereas downward flexibility is provided when the generation is below the hourly target production. As such, the upward flexible power is calculated as the average deviation above the hourly target production, whereas the downward flexible power is defined as the average deviation below the hourly target production.

Overall, the total activated upward and downward flexibility are 12.7 TWh and 12 GWh, respectively.

3.9. District heating – CHP

District heating – CHP is modelled as aggregated CHP plants with a daily generation requirement which is linked to the daily heat demand. CHP units are defined as part of a heating area for which they must fulfil certain level of generation per day, which represents the required heat consumption. Therefore, flexible power and flexibility activation are calculated following the same method as for industrial heating, namely CHPs.

The total activated upward and downward flexibility are 59.6 TWh and 14.0 TWh, respectively.

4. QUANTIFICATION OF DSF BENEFITS IN 2030

4.1. Wholesale markets and adequacy

The underlying assumption of this study is that wholesale market benefits outweigh the potential DSF benefits such as balancing or infrastructure savings, hence DNV's main focus was on the modelling and methodology to derive these market benefits. This section and the following ones prove that this assumption is correct and wholesale market benefits are significantly higher than the rest.

To quantify the effect of the optimal DSF deployment on wholesale markets in EU 27, DNV has modelled and simulated the European Power Market for the year 2030 (for the DSF and the no-DSF scenario), as described in section 2.[10] The benefits were subsequently quantified by different metrics as the difference between the results for both scenarios:

- **Cost to generate:**

These are the costs that generators/storage incur to cover the system demand. These include fuel costs, variable operation and maintenance (VOM) costs, start and shutdown costs, emissions costs and penalties.[11]

- **Loss of load:**

This is the total amount of load that has not been served by the available generation. The cost used to monetise the loss of load is set to 3,500 €/MWh. The actual valuation will strongly depend on the context, in particular the degree of acceptability of load shedding and load curtailment as a mean of system adequacy.

- **Renewable energy curtailment:**

This includes the curtailment of renewable energy generators for economic reasons and interconnector congestion considerations.

- **Greenhouse gas emissions:**

These are the total emissions by generators to cover the power demand.

- **Cost to serve load:**

This is the total price that load needs to pay for their electricity intake. The price for the load is considered as the day-ahead hourly spot price.

10. More details on the methodology and limitations of his methodology can be found in Appendix A – section 1.1
11. Penalties apply when a generator or a demand unit violates a constraint, e.g. a district heating CHP would pay a penalty when it generates less than the required production.

The results (Table 4.1) indicate that, in 2030, with the activation of 397 TWh upward DSF and 340.5 TWh of downward DSF:

- The cost to serve load, i.e. the cost that consumers pay for their electricity consumption, is around €301.5 billion (48%) less than in the no-DSF scenario;

- The system meets and even exceeds the necessary emission reduction in the power sector to fulfil the 55% GHG reduction, whereas the no-DSF scenario does not achieve the target;

- The emissions are 37.5 million tonnes (8%) less than in the no-DSF system;

- Costs to generate are €4.6 billion (5%) less than in a no-DSF system;

- The system can serve all demand throughout the year, whereas the no-DSF system cannot serve all the 2,054 GWh of load in 2030. Therefore, the DSF system saves €9 billion on value of lost load; and

- Renewable energy curtailment is 15.5 TWh (61%) less than in the no-DSF scenario.

Cost to serve load benefits are significantly higher than the rest of the parameters. This highlights the considerable impact that load curtailment and load shifting have on the generation mix for each moment. DSF avoids the creation of high peaks where very expensive (and price setting) generators are needed, and absorbs the energy in the case of a generation surplus and relatively low prices. Therefore, it can be observed that even if the generator costs are only 5% less, the lower utilisation of expensive generators makes a tremendous impact on the final cost to load (nearly 50%).[12]

Table 4.1 – Wholesale benefits of DSF

Year 2030 – EU 27	Benefits (DSF scenario vs. no-DSF scenario)	Relative to no-DSF scenario
Cost to serve load	- €301.5 bn	- 48%
Emissions	- 37.5 Mt	- 8%
Cost to generate	- €4.6 bn	- 5%
Value of loss of load	- €8.97 bn	- 100%
Renewable energy curtailment	- 15.5 TWh	- 61%

12. It should be noted that if the security of supply was met in the no-DSF scenario, there would have been a (lower) different outcome on benefits.

The strong impact of DSF on the (residual) demand curve leads to a shift from generator's surplus to consumer's surplus. When comparing the DSF to the no-DSF scenario, the larger part of the savings on the cost to serve can therefore be attributed to the reduction of generator's margins (which are, at least partly, required to cover the initial investments). This impact is further specified in Table 4.2, which shows the total generation margins per type of generation technology, for both scenarios. Since the no-DSF scenario is not realistic, these figures do not fully describe the impact of full DSF deployment on the investment climate for different generation technologies. It does indicate, however, which technologies are affected most when deploying DSF to its full potential:

- Profitability of fossil fuel plants is very strongly impacted as both their running hours and market price volatility are strongly reduced;

- Profitability of nuclear plants is strongly impacted mainly due to reduced market price volatility, however nuclear can benefit from the floor price already noticeable in the no-DSF scenario, see also Figure 11;

- Profitability of renewables is somewhat impacted. However, the large amount of electrolysers and front-of-meter storage already creates a floor price in the no-DSF scenario, and therefore the impact for renewables seems limited;

- Profitability of biomass is strongly impacted, although less than fossil-fuel generators.

Table 4.2 – Impact of DSF on generator types

Generation technology type	Fossil fuel			Nuclear			Renewable			Biomass		
Billion €	Revenues	Costs	Margin	Revenues	Costs	Margin	Revenues	Costs	Margin	Revenues	Costs	Margin
No-DSF scenario	175,698	83,733	91,965	101,570	4,527	97,043	218,151	4,924	213,227	29,425	3,802	25,624
DSF scenario	86,359	77,369	8,990	48,648	4,594	44,054	158,553	4,440	154,113	11,577	4,201	7,376
Relative change			-90%			-55%			-28%			-71%

The impact of a full deployment of DSF on market price volatility is further demonstrated by the price duration curves below.

Figure 10 – Price duration curves for both scenarios, full (left) and zoom-in (right)

Both graphs clearly demonstrate that, whereas a price floor already exists in the no-flex scenario (due to large amounts of electrolysers and front-of-meter storage), the DSF scenario further reduces price volatility, rendering a relatively flat price duration curve for 2030.

Adequacy considerations

The analysis above shows that the no-DSF scenario does not maintain security of supply, showing a loss load of 2,054 GWh. In terms of capacity, the no-DSF scenario lacks up to 60 GW of generation capacity during the highest peak in residual load. In the DSF scenario, the system fulfils the lack of generation capacity with load shifting and load curtailment.

While a full adequacy analysis was not the scope of this study[13], this analysis gives an indication of the minimum gap (60 GW) that would need to be covered by additional peak generation. Since the DNV model only considers marginal costs, it does not quantify the capital expenditure (CAPEX) benefits related to generation adequacy, i.e. avoiding the construction of (in this case approximately 60 GW) additional capacity. Therefore, DNV calculated an indicative adequacy benefit of DSF by comparing 1) the investment required for installing 60 GW of peak generation capacity; and 2) the costs of enabling 60 GW of DSF. The difference between them is defined as the DSF adequacy benefit. The following assumptions have been made:

- Additional generation capacity does not come from carbon-free technologies, since there are more cost-effective ways for decarbonising the system than constructing carbon-free generators that run less than 100 hours per year. Therefore, the price of gas peaking plants is considered.

- For DSF, the costs of industrial DSF are considered, as these are likely to play a dominant role in scarcity situations. This is limited to the (annualised) enablement costs of DSF. Typically, industrial customers also require annual (capacity) payments for participating in services with low activation frequencies. Because these payments are direct benefits for consumers, they are not considered as additional costs to consumers.

The table below gives a rough indication of the capital investment needed for both options. The gas peaker option is substantially more expensive than the investment needed for installing 60 GW of DSF. Therefore, DNV concludes that, roughly, **the adequacy benefit of DSF in 2030 is €2.7 billion.**

Year 2030 – EU 27	Cost [€/MW/year]	Total cost [million €]
Gas peaker CAPEX (annualised)	45,500 (LAZARD, 2020)	2,730
DSF CAPEX	120 (European Commission DG Energy, 2016)	7.2

13. An adequacy study needs stochastic modelling to draw statistically valid conclusions. The modelling used for this study was deterministic, and therefore not sufficient.

4.2. System balancing

DNV's market model calculates day-ahead (DA) spot prices, and does not consider balancing energy and associated costs. Therefore DNV has quantified the savings, that DSF could potentially bring to balancing markets by 2030, following a simplified methodology presented in Appendix A – section 1.2. The quantification considers the difference between energy balancing costs of the DSF and no-DSF scenarios in 2030. Given the relatively small size of balancing markets compared to wholesale markets, DNV performed the calculation under four main assumptions:

1. By 2030, balancing energy will be procured at European level, not country level;

2. There is sufficient interconnection capacity so all balancing resources at European level are available to all Member States, therefore assuming that current restrictions regarding excessive reliance on importations of balancing services no longer apply;

3. Balancing capacity costs and balancing energy utilisation will remain at current levels; and

4. The balancing energy costs are determined by the marginal costs of technologies technically capable of providing the different balancing services.

Under these assumptions, DNV first identified DSF and no-DSF technologies that could technically provide the different balancing services and their associated marginal costs. DNV then built a merit order for each balancing service for each scenario (DSF and no-DSF). Subsequently, based on the required balancing capacity, DNV identified the technologies that would cover the balancing needs. Finally, the costs for balancing energy were calculated for a full year based on the marginal costs of the technologies 'in the money' as well as the savings, i.e. the difference in cost between scenarios.

DNV's calculations showed that the participation of DSF technologies in European balancing markets in 2030 could save, in total for EU 27, **between €262 million and €690 million.** In relative terms, this translates into a balancing energy cost saving of between 43% and 66%. The wide range of savings is due to the uncertainties related to the different balancing capacity needs for all EU 27 members. The different capacity needs correspond to different price levels in the balancing merit order, which in turn translate into a wider saving range.

It is worth noting that one of the limitations of the approach is that the quantification does not consider opportunity costs for participating in other markets. A more elaborate overview of the approach is presented in Appendix A – Section 1.2.2.

4.3. Grid infrastructure

As previously described in section 2, DNV's market model does not include distribution grid restrictions or local flexibility markets. Therefore, DNV has created a simplified methodology, based on the limited data available, to quantify the required investments in distribution grids between 2023 and 2030 and the infrastructural benefits of DSF. A detailed description of the methodology is presented in Appendix A – Section 1.1.
The methodology is built under these main assumptions:

1. All available DSF flexible power behaves in a grid-friendly manner. This means that flexibility responds to network needs either through (collective) self-consumption, grid tariff optimisation or provision of flexibility services to distribution system operators.

2. Distribution grid investments are mainly driven by final electricity demand, adoption of EVs and RES capacity.

3. The potential savings are proportional to the ratio of DSF available capacity and peak load.

In summary, this methodology consists of both a top-down and bottom-up phase. In the former, the required distribution grid investments at EU 27 level are calculated and distributed across Member States according to their share of electric load, electric vehicles, and RES capacity connected to the distribution grid. In the latter, based on available DSF capacity relative to peak load, savings in infrastructural investments are estimated per Member State and then aggregated at EU 27 level. Investments required for the modernisation, digitalisation, automation, and resilience of the distribution grids are not accounted for.

According to (Eurelectric, 2021), investment needs in distribution grids are mostly driven by the final electricity demand, the number of electric vehicles, and the renewable capacity connected to the distribution grid.[14] Based on the input data, calculated DSF capacity and the investment breakdown per driver derived from (Eurelectric, 2021), DNV estimates that the EU 27 required investments in distribution grids to integrate new loads and RES capacity are between €253.1 billion and €282.5 billion between 2023 and 2030.

The results of the grid simulations in (E-Bridge, 2019) show that the grid-friendly use of DSF capacity can reduce by 76.9% the required investments in low-voltage and medium-voltage distribution grid expansion in Germany by 2035. Assuming a linear relation between DSF available power and the investment savings, DNV estimates that DSF can enable **savings between €77.6 billion and €203.6 billion (i.e. between -27% and -80%) at EU 27 level between 2023 and 2030.** Assuming that the annual investments are constant, the annual savings in 2030 are estimated between €11.1 billion and €29.1 billion. The large range of potential savings is due to the top-down approach taken to quantify the grid investment needs per Member State. This is due to the uncertainties on the extent to which each country will contribute to the total estimated investments, and hence to the benefits enabled by available DSF.

The quantification approach proposed by DNV focuses on the investments required in low-voltage and medium-voltage distribution grids only and does not include high-voltage grid or transmission grids. This means that potential savings on transmission grid reinforcements or DSF contribution to lowering redispatch costs have not been quantified. Additionally, it does not consider differences across countries regarding the current status of development of the distribution grid and voltage level in the distribution grid. A more elaborate overview of the approach limitations is presented in Appendix A – section 1.3.3. Overall, DNV acknowledges the lack of studies on the quantification of infrastructural benefits of DSF. DNV interprets this as a signal for relevant stakeholders to further investigate the topic.

14. These grid investment needs refer particularly to the needs raised by higher electrification and connection of renewables.

5. QUANTIFICATION OF CONSUMER BENEFITS

Here, the DSF benefits at system level calculated in the previous section are translated into benefits to the consumer. Direct benefits end up at residential, commercial and industrial consumers with flexible loads, for example, EV owners who exploit the flexibility of their EVs face lower energy costs when EV charging is exposed to dynamic prices. Additionally, all consumers will gain indirect benefits, due to the overall effect on market prices.

5.1. Direct benefits

The direct benefits are those that the consumer sees directly reflected in their energy bill[15], as either a saving or a revenue (e.g. batteries). Thus, these benefits can be split per type of technology in 2030, which gives an average indication of the savings per energy unit. DNV calculated the savings/revenues depending on the type of DSF technology, excluding capital investments for enabling or acquiring the different DSF technologies:

- Smart charging and space electric heating: The savings are calculated as the difference between the cost to source their required amount of energy in the DSF and no-DSF scenarios in 2030.

- Battery storage and V2G: The savings are calculated as the difference between battery/V2G profits for both scenarios in 2030. The profits are defined as the difference in revenue generated by energy infeed and the costs (charging and variable maintenance and operation costs).

- Industrial electric heating: The savings are calculated as the difference between the energy costs of both scenarios. The difference in energy costs is caused by the load curtailment in the DSF scenario and the different energy prices.

- Industrial DSR: The savings are calculated as the reduction in energy costs due to curtailment minus the cost incurred due to curtailment.

Table 5.1 includes a summary of direct benefits to consumer.

The highest savings are achieved on space electric heating with a potential cost reduction of €71 billion in 2030 for EU 27. These savings could be even greater when taking energy-efficiency considerations into account. Some studies indicate that residential flexibility activations also accomplish a reduction of the overall load. For instance, an RTE study (RTE, 2016) suggests that energy savings up to 50% could be achieved. However, DNV has not modelled these aspects due to lack of evidence applicable to all Member States throughout a full year.

An average EV owner could save up to 0.07 €/kWh, which adds up to a saving of 176 €/year on their energy bill in 2030. The average includes both smart charging and V2G savings.

It can also be observed that behind-the-meter revenues are significantly lower than the rest. Partly, this is due to efficiency cost considerations.

Finally, industrial DSR figures show the savings that can be achieved through (market-based) load curtailment only, i.e. the reduction in total energy payment due to different energy prices is not included in the calculations.

15. This is assuming that these customers are exposed to dynamic prices that reflect wholesale prices. Other remuneration models are also conceivable, e.g. fixed energy prices with a separate remuneration for providing flexibility.

Table 5.1 – Direct consumer benefits in the DSF- versus the no DSF-scenario

Year 2030 – EU 27	Savings and revenues (million €)	% Relative to no-DSF costs (%)	Average saving/revenue per kWh (€/kWh)
Smart charging + V2G	9,936	48%	0.07
Space electric heating	71,234	64%	0.16
Battery storage BTM	32	100%	0.08
Industrial electric heating	5,166	51%	0.05
Industrial DSR (curtailment)	232	100%	0.01

5.2. Indirect benefits

The changes in system costs and energy prices will have an impact on all final consumers. The indirect potential benefits that DSF provides to the consumer are:

- The overall reduction of energy prices (i.e. the reduction of cost to serve consumer's load)
- The reduction of generation capacity costs
- The decrease in investment for grid infrastructure
- The decrease of system balancing costs
- The decrease of carbon emissions

Based on the results from the previous sections, Table 5.2 summarises the indirect impacts to all consumers, in absolute terms and per capita. The results indicate that the most significant saving is due to the reduction of energy costs, **with an average reduction of €673.5 in energy cost per capita in year 2030.** As previously detailed in section 4.1, this is due to the effect of DSF in peak shaving and reduction of renewable curtailment, which avoids the use of more expensive generation. Following the energy prices, and with a lower order of magnitude, are infrastructure savings per year, representing €27.8 to €65 per capita in year 2030. The savings with the lowest impact are balancing services, at €0.7 to €1.6 per capita in year 2030; these savings are relatively low because the size of the market is significantly smaller compared with wholesale. Finally, one of the benefits for all consumers is the lowering of carbon emissions by 83.8 kg per capita, which would fulfil the 55% reduction by 2030.

Whereas end consumers benefit from reduced electricity market prices, generators will substantially lose margin on their transactions. This effect is the strongest for fossil, nuclear and biomass power plants; the impact for renewables is substantially less as these can also benefit from additional load during times of high renewable generation. An overview of generator margins and further considerations in the implications are presented in section 4.1.

Table 5.2 – Indirect consumer benefits

Year 2030 – EU 27	Potential savings	% Relative to no-DSF	Potential savings per capita[16]
Cost to serve load	€301.5 billion	-48%	€673.5
Adequacy	€2.7 billion	-100%	€6.0
Balancing	€0.3–0.7 billion	[-66%,-43%]	€0.7–1.6
Infrastructure[17]	€11.1–29.1 billion	[-80%,-27%]	€27.8–65
Emissions	37.5 Mt	-8%	83.8 kg

16. Savings per capita are calculated for 447.7 million inhabitants in EU 27 (eurostat, 2020).
17. It should be noted that the reference for the calculation of infrastructure benefits is not the 'no DSF' scenario. This is due to the methodology applied to this calculation. The savings and relative calculation are based on the investments needed as predicted today in a business-as-usual situation.

While the above categories are all potential benefits of DSF, they are not stackable and therefore the benefits cannot be simply summed up to a total. The next section provides further insight on how these results can be interpreted.

5.3. Stackability considerations

In its methodology, DNV has assessed the value of DSF in the different segments separately, – i.e. wholesale, generation adequacy, balancing and infrastructure. Analysis shows that the potential value is significant, especially for the costs to serve load.
This study assumes that all DSF technologies have access to these segments and will be activated based on a market-based mechanism – provided that they meet the technical requirements (mainly balancing) and geographical requirements (mainly infrastructure).

For estimating the total value of DSF, the three separate outcomes cannot simply be added. Although 'value-stacking' (participating in different markets at the same time) of DSF in general is allowed, there are clear physical limitations to this concept, for example:

- If a flexible EV charger is charging at maximum capacity due to low wholesale prices, it cannot increase its load to provide balancing power (it can only provide balancing power in one direction in this case).

More delicate is the combination of wholesale and infrastructure. The deployment of DSF can improve both segments at the same time but can also create conflicts. Considering the same EV charging example:

- Optimising EV charging against wholesale prices will reduce EV charging load during late-afternoon peak hours, reducing the stress on grid infrastructure in (urban) load centres;

- Optimising EV charging against wholesale prices will increase EV charging during periods around noon with high solar-PV power production, reducing the need for (market) PV curtailment, but increasing the stress on grid infrastructure in solar-PV dominated (rural) areas.

The DNV model has not taken any limitations on the distribution grid into account. This means that when DSF is deployed to reduce infrastructure costs, this will lower the benefits for the cost to serve load. Since the potential benefits on infrastructure are significant, albeit lower than benefits for the cost to serve load, there is a compelling reason to look for the middle ground of market and infrastructure optimisation. Using a proper market design, where all DSF not only is exposed to market prices as well as cost-reflective grid fees and DSO flexibility services, can ensure that the benefits for the customer are optimal, and will exceed the value of benefits to the cost to serve load only.

Generation adequacy benefits have been calculated outside the wholesale model by considering CAPEX costs of generation assets that would be needed to solve the generation deficiency of the no-DSF scenario. Including these assets for the no-DSF scenario within the model would lower the calculated wholesale benefits.

6. KEY TAKE-AWAYS AND RECOMMENDATIONS

In 2030, the activation of 397 TWh upward DSF and 340.5 TWh of downward DSF enables Fit for 55 and REPowerEU strategy by 2030 while achieving a cost reduction on:

- Wholesale and adequacy

  - The cost to serve load is up to around **€301.5 billion** (48%) less;

  - The emissions are up to **37.5 Mt** (8%) less;

  - Costs to generate are up to **€4.6 billion** (5%) less;

  - Renewable energy curtailment is up to **15.5 TWh** (61%) less; and

  - The costs saved on installed generation capacity are up to **€2.7 billion** less.

- Balancing energy costs are estimated to be **between €262 million and €690 million** less (43% and 66%)

- Grid infrastructure savings in low-voltage and medium-voltage are between €77.6 billion and €203.6 billion (i.e. between-27% and-80%) at EU 27 level between 2023 and 2030. The annual savings in 2030 are estimated to be **between €11.1 billion and €29.1 billion.** These savings are based on the hypothesis that grid-driven optimisation is implemented, which may not always be the case in the above-mentioned market-driven optimization cases. The potential savings on transmission grids due to avoided reinforcement and re-dispatch costs are not quantified.

This translates into direct and indirect consumer benefits. The direct benefits are achieved by a direct saving due to the shifting or curtailment of the load, whereas indirect benefits are achieved due to the impact of DSF activation in the entire system and its energy costs.

- **Direct benefits**: The users of DSF technologies can save between €0.01 and €0.16 per kWh. The results indicate that the highest savings are achieved in space heating, with a 64% cost reduction, followed by EV charging with a 48% cost reduction (€0.07 per kWh saving). The lowest savings are achieved by DSF technologies with higher variable operation and maintenance costs, such as industrial DSR and, to a lesser degree, batteries. These benefits are also reflected in the indirect benefits; therefore, they should not be double-counted.

- **Indirect benefits:** The results indicate that the most significant saving is due to the reduction of electricity costs, reducing the costs to consumers by up to €673.5 per person in the year 2030. This is due to the effect of DSF in peak shaving and reduction of renewable curtailment, which avoids the use of more expensive generation. Following the electricity prices, and with a lower order of magnitude, are infrastructure savings of between €27.8 and €65 in cost reduction per capita in a year in 2030. The savings that would make the least impact are those in balancing costs (€0.7 to €1.6 per capita in 2030); these are relatively low because the size of the balancing market is significantly smaller than wholesale trade. Finally, one of the benefits for all consumers is the reduction of carbon emissions. The DSF scenario would fulfil the 55% reduction by 2030, while the no-DSF would not.

DNV calculated the savings that full DSF enablement (~160 GW in capacity across EU 27) by 2030 would achieve against a scenario in which DSF is not available. The lack of data on the utilised DSF today and DSF utilisation prospects towards 2030 makes it impossible to quantify the counterfactual system costs. Therefore, DNV modelled a 2030 scenario in which DSF technologies are not flexible. Realising that demand-side technologies are to some extent – and in some Member States more than others – already actively participating in the electricity market, DNV acknowledges that **the reference scenario is not a realistic scenario.** Therefore, all results, should be interpreted as the **total potential benefit of DSF.** If, by 2030, certain barriers still exist to DSF fully participating in the electricity market, a certain share of this potential will not be achieved. **The results provide an order-of-magnitude value of this missed opportunity (albeit an upper bound).**

The study presents several limitations, partly due to data unavailability at European level. Moreover, the results raised some questions that are worth analysing further. Therefore, **DNV recommends to:**

- Improve transparency on the current deployment of DSF in wholesale and balancing markets throughout EU 27 by introducing market monitoring in a structured and harmonised manner on DSF availability and deployment;

- Assess and mitigate any regulatory, economic (e.g. grid tariff methodology), and/or business (case) challenges that may cause bottlenecks to further DSF deployment;

- Develop a common methodology to quantify the potential infrastructure savings resulting from a full deployment of DSF per Member State;

- Analyse which holistic market design (including grid fee methodology and DSO flexibility services) can achieve the optimal DSF deployment results for the combination of both markets and infrastructure;

- Investigate energy-efficiency potential resulting from DSF deployment; and

- Investigate the impact of more large-scale DSF deployment on the investment climate for renewables generators.

APPENDIX A – Detailed Methodology Description

1.1. Quantification of wholesale and adequacy benefits

1.1.1. QUANTIFICATION APPROACH

DNV has used its European Market Model which is a fundamental market model that simulates the day-ahead spot price by optimising the unit commitment and economic dispatch of electricity generation. The simulations are performed on an hourly time-resolution containing a detailed representation of generation, commodity prices and demand for all bidding zones in EU 27 Member States. The description of the model inputs is described in section 2.

Among other parameters, the market model outputs the hourly demand and generation mix, the hourly day-ahead energy prices, and the total system emissions.

DNV has used the outputs of the model to quantify the wholesale benefits. To do that, DNV has created two a reference scenario to compare the 2030 results ("DSF scenario") – with full DSF potential – against. As explained in section 2.4, DNV modelled a 2030 scenario in which the demand side is not flexible to serve as a reference scenario, albeit not realistic.

In the next section (1.1.2), there is a detailed explanation on the approach taken to model the selected DSF technologies in the DSF and no-DSF scenarios. The main underlying assumptions to our modelling are:

- DNV considers the full theoretical potential of DSF of the selected technologies, although in practice some consumers may not be interested to participate.

- Some flexibility may not be available to the market, as it is used for 'in-building' optimisation, e.g. to increase self-consumption or to reduce grid fees. This is not explicitly considered, because

    - the grid benefits are determined separately (outside the model), this model focuses on the market benefits.

    - In practice, the behaviour triggered by in-building optimisation, is very similar to the behaviour triggered by market optimisation. For example, a home battery will typically charge around noon on a summer day whether there is local PV (in-building optimisation) or not (market optimisation).

- Time shifters (e.g. electric heating, EV charging and batteries) do not have marginal costs, they are simply optimised against wholesale prices within time constraints. Battery and V2G need to take efficiency losses into account, so there should be sufficient spread between charging and discharging prices to cover these costs.

Wholesale

Using the output of the model, DNV calculates the wholesale benefits by comparing the DSF and no-DSF scenario:

- Total carbon emissions in 2030: This is a direct output of the model and it's based on the carbon-based fuel and biomass used by the dispatched generators. The carbon capture and storage impact is also considered in the results. The resulting emissions are then evaluated against the targeted 2030 power system emissions to fulfil the 55% emission reduction objective. This power sector emission target is based on DNV's energy transition outlook model and it's set at 410 eq. CO_2 million tonnes.

- Total curtailment volume in 2030: This is calculated by subtracting the realised solar and wind generation to the available generation in a given hour, for all the hours of the year. The curtailment can be due to economic reasons or interconnector capacity limitations. The model does not consider curtailment due to distribution and transmission constraints within the bidding zone.

- Total generator costs: This is a direct output from the model. These are the costs that generators/storage incur to cover the system demand. These include fuel costs, variable operation and maintenance (VOM) costs, start and shutdown costs, emissions costs and penalties. Penalties apply when a generator violates a constraint, e.g. a minimum generation requirement.

- Loss load (unserved load): This is calculated as the sum of the hourly demand that is not met in 2030.

- Cost to serve load: This is calculated for all loads in a year and is defined as the price paid by the load times the demand. The price paid by the load is the volume-weighted price paid for all energy purchases in 2030.

Adequacy

To have a rough estimation of DSF adequacy benefits, DNV also relies on the market model simulations results. The approach is as follows:

- **1. Calculate the demand power that was not served by generation in the no-DSF scenario.**

- **2. Calculate the CAPEX needed to install a generation plant that can cover the generation power deficiency.**

- **3. Calculate the CAPEX needed to enable the same power, as in step 2, of industrial DSR.**

- **4. The rough estimate (lower bound) of DSF benefit to generation adequacy is calculated as the difference between step 3 and step 2 results.**

1.1.2. DEMAND AND DSF MODELLING APPROACH AND INPUT PARAMETERS

In this section, the modelling of the different technologies is explained in detail, for both the DSF and no-DSF scenarios.

1.1.2.1. Industrial DSR

Industrial DSR is modelled as a generator whose generation corresponds to an industrial load (partially) shutting down its consumption. Industrial DSR is defined per country and distinguished in five types of industrial load. Each type is defined by the following parameters:

- Installed capacity [MW]: max generation, i.e., max curtailable load. It is defined as the total industrial DSR capacity multiplied by a percentage that varies per type.

- Variable O&M [€/MWh]: cost of shutting down the industrial load

- Max Up Time [h]: maximum number of consecutive hours the industrial load can be curtailed

While the total industrial DSR capacity varies per country, the distribution across load types, the variable O&M, and the max up time are the same, as shown in Table 1.1.

Table 1.1 – Industrial DSR parameters per load type

Type of DSR	Percentage of total DSR capacity	Variable O&M [€/MWh]	Max Up Time [h]
Category 1	10%	1000	1
Category 2	35%	1097	2
Category 3	9%	323	4
Category 4	30%	500	8
Category 5	16%	207	-

The values for the abovementioned parameters are derived from several sources, which are listed in Table 1.2 – Industrial DSR data sources. Countries not listed in Table 1.2 are expected to have no industrial DSR installed capacity in 2030.

Table 1.2 – Industrial DSR data sources

Country	Total installed capacity	Percentage per type	Variable O&M	Max Up Time	Note
AT	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
BE	(Elia, 2021)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
DE	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
EE	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
ES	(ENTSO-E, 2020)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	ES data are not reported in (ENTSOG and ENTSO-E, 2022)
FI	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
FR	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
HR	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
IE	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
IT	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
LT	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
LV	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
NL	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
SE	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	
SI	(ENTSOG and ENTSO-E, 2022)	(Elia, 2019)	(ENTSO-E, 2021)	(Elia, 2019)	

The Variable O&M is derived from (ENTSO-E, 2021) by calculating the weighted average price across countries per DSR type according to the max up time value.

No industrial DSR units are modelled in the no-DSF scenario.

1.1.2.2. BESS

Batteries are distinguished in behind-the-meter and grid-connected BESS. Both types are defined by the following parameters:

- Units: number of units (following properties are defined per unit).
- Max Power [MW]: charging/discharging max power capacity per unit.
- Capacity [MWh]: capacity of each unit. A battery storage duration of 3 hours is assumed, which is comparable to Li-ion technology.
- Min SoC [%]: minimum state of charge of a unit.
- Initial SoC [%]: initial state of charge of a unit.
- Charge/discharge efficiency [%].
- Max Cycles Day: number of cycles allowed each day.

BESS charge and discharge depending on the power price (see illustrative example in Figure 4), while satisfying some constraints, namely, maximum charging/discharging power, maximum storage capacity, minimum SoC, and maximum cycles per day. For the battery to be activated, the power price needs to show a sufficiently large spread in one day look-ahead to overcome the cost of energy due to efficiency losses.

The values of the abovementioned parameters are mostly based on expert knowledge and are summarised in Table . The number of units per BESS type per country are derived from multiple sources, which are listed in Table 1.4.

Table 1.3 – BESS techno-economic parameters

Max Power [MW]	Capacity [MWh]	Min SoC [%]	Initial SoC [%]	Charge/discharge efficiency [%]	Max cycles day
100	300	20	50	85	2

Table 1.4 – BESS data sources

Parameter	Source
Total number of batteries per country	(ENTSO-E, 2020), (DNV, 2021)
Split between behind-the-meter and grid-connected	(EASE)

1.1.2.3. Smart charging

EVs are modelled using the following parameters:

- Max load [MW]: maximum hourly (charging) capacity.
- Max Daily Consumption [GWh]: maximum daily load
- Min Daily Consumption [GWh]: minimum daily load

EV charging load is optimised by the Market model. However, it is subject to a daily load equality constraint that cannot be violated, i.e., max energy day = min energy day.

Max load – maximum hourly (charging) capacity

The maximum hourly (charging) capacity is calculated based on the maximum power capacity per country and an availability profile. The maximum power capacity per country is calculated based on the numbers of charging points per country times the maximum power capacity per car. The model assumes 10 kW/car.

The availability profile represents the share of charging points occupied by a car per hour.

Max daily consumption and Min daily consumption – maximum/minimum daily load

The minimum and maximum daily load is calculated based on the annual EV consumption per country divided by 365. The annual EV consumption per country is calculated based on the number of EVs times the annual consumption per car, which is assumed equal to 2.5 MWh/year.

An overview of the input parameters is given in Table 1.5.

Table 1.5 – EV technical parameters

Max Power [MW]	Max energy capacity [kWh/car]	Annual consumption [MWh/year/car]
10	61.5	2.5

In the no-DSF scenario, EVs follow an hourly charging profile which they cannot deviate from.

The abovementioned parameters and availability profiles are derived from multiple sources which are listed in Table 1.6.

Table 1.6 – Smart charging data sources

Parameter	Source	Note
Number of EVs per country	(DNV, 2021) and industry insights	BEV and PHEV data
Number of CPs per country	(DNV, 2021) and industry insights	Home and workspace data
Availability profile	(ElaadNL, 2020), (UK Government, 2022), (California Institute of Technology, 2021)	
Charging profile (no-DSF)	(ElaadNL, 2020), (UK Government, 2022), (California Institute of Technology, 2021)	

1.1.2.4. V2G

It is assumed, based on expert knowledge, that 30% of the EV charging infrastructure provides V2G possibility. V2G is modelled as batteries with the following parameters:

- Capacity [MWh]
- Max power [MW]: power at full discharge
- Max load [MW]: power at full charge
- Initial SoC [%]
- Charge/discharge efficiency [%]
- Max Cycles Day: number of cycles allowed each day.

Capacity

It corresponds to the storage capacity available for V2G. It is calculated based on the number of EVs per country times the max energy capacity per car, and on the assumption that 30% of the grid connected EVs provides V2G capacity.

Max power and max load – power at full discharge/charge

It corresponds to the power capacity available for V2G. It is calculated based on the EV max load (see Section 1.1.2.3) and on the assumption that 30% of the EVs provides V2G capacity.

An overview of the input parameter is given in Table 1.7. Data sources are the same used for smart charging (see Table 1.6).

Table 1.7 – V2G techno-economic parameters

Initial SoC [%]	Charge/discharge efficiency [%]	Max cycles day
50	93	2

V2G is not modelled in the no-DSF scenario.

The abovementioned parameters are derived from multiple sources which are listed in Table 1.8.

Table 1.8 – EV data sources

Parameter	Source
% V2G charging infrastructure	(European Commission, Directorate-General for Energy, 2022)

1.1.2.5. Residential electric heating

Residential electric heating represents residential and commercial space heating electricity demand. It is considered as a shiftable load, and it is modelled using the following parameters:

- Max Load [MW]: maximum hourly consumption.
- Min Load 12 h [GWh]: maximum total space heating consumption in 12-hour day/night period.
- Max Load 12 [GWh]: minimum total space heating consumption in 12-hour day/night period.

Residential electric heating load is optimised in the Market model. However, it is subject to a 12-hour load equality constraint that cannot be violated, i.e., min load 12 h = max load 12 h. Therefore, it can provide flexibility by shifting the consumptions while respecting the 12 hours load requirement.

Max load – maximum hourly consumption

Max load corresponds to the maximum possible consumption from residential space electric heating in every hour, per country. The maximum load is the same for every hour.

Min and Max load 12 h – maximum/minimum consumption in 12-hour period

The minimum and maximum daily load is cal culated based on the annual residential electric heating consumption per country, distributed among the days based on a daily space heating demand profile. This daily consumption is divided in two periods of 12 hours each, i.e. half of the total daily consumption is required in each 12-hour period.

The 12-hour periods are defined as:

- Day period: from 9 a.m. to 9 p.m.
- Night period: from 9 p.m. to 9 a.m.

The minimum and maximum 12-hour load is defined with the same value. Therefore, the consumption can be shifted across a 12-hour timeframe, but the required consumption (minimum and maximum) must be fulfilled in those 12 hours.

In the no-DSF scenario, residential electric heating follows an hourly consumption profile per country, from which there cannot be deviations. Hence, demand cannot be shifted across time.

The abovementioned consumption values and daily profiles are derived from multiple sources which are listed in Table 1.9.

Table 1.9 – Residential electric heating data sources

Parameter	Source	Note
Annual electricity demand	(ENTSOG and ENTSO-E, 2022)	Residential Space heating and Tertiary space heating data. Scenario Distributed Energy.
Daily and hourly heat demand profiles	(Ruhnau, O., Hirth, L. & Praktiknjo, A.)	Single-family house, multi-family house, and commercial building data.

1.1.2.6. Industrial electric heating

Industrial electric heating is considered as a curtailable load, and it is modelled using the following parameters:

- Max Load [MW]: maximum hourly consumption.
- Bid Quantity [MW]: demand bid.
- Bid Price [€/MWh]: price of the demand bid.

Industrial electric heating load can reduce part of its consumption when prices reach a certain activation price.

Max load – maximum hourly consumption

Max load corresponds to the maximum possible consumption from industrial electric heating in every hour, per country. The maximum load is the same for every hour.

Bid quantity – demand bid

Bid quantity represents the hourly consumption from industrial electric heating, and is defined with the same values as Max Load. Therefore, bid quantity is the hourly consumption and also the maximum possible load shedding.

Bid price – price of the demand bid

Bid prices represents the activation price for industrial electric heating curtailment. The load will be curtailed if the prices reach this specific bid price. The bid price is defined as 500 €/MWh.

In the no-DSF scenario, industrial electric heating cannot curtail the consumption.

The values of the abovementioned parameters are mostly based on expert knowledge and DNVs internal data.

1.1.2.7. Industrial heating – CHP

Industrial heating from CHP units is represented by CHP generators with hourly generation requirements. The units can deviate from the generation requirements by incurring certain penalty. These units are modelled as standard generators, with several additional parameters:

- Min Energy Hour [MWh]: minimum hourly generation.
- Min Energy Penalty [€/MWh]: penalty for not reaching the minimum hourly generation.

Min Energy Hour – minimum hourly generation.

The minimum generation per hour is defined depending on the hour of the day:

- Peak hours: from 5 a.m. to 8 p.m. the unit should generate at 100% of its capacity.

- Off-peak hours: from 8 p.m. to 5 a.m. the unit should generate at minimum 65% of its capacity.

Min Energy Penalty – penalty for not reaching the minimum hourly generation

If the generation does not reach the required level defined by Min Energy Hour, then a penalty is incurred. The value of this penalty is defined as 1000 €/MWh.

In the no-DSF scenario, industrial heating CHPs cannot deviate from the generation requirements described above. Deviations by either not reaching or surpassing the requirement are not allowed.

The values of the abovementioned parameters are mostly based on DNVs internal data.

1.1.2.8. District heating – CHP

District heating residential CHP units are represented by CHP generators with daily generation requirements which are linked to the daily heat demand. CHP units are defined as part of a heating area for which they must fulfil certain level of generation per day, which represents the required heat consumption. These units are modelled as standard generators, with several additional parameters:

- Min daily generation [GWh]: minimum daily generation.
- Min daily generation penalty [€/GWh]: penalty for not reaching the minimum daily generation.

Min daily generation – minimum daily generation

The minimum daily generation of each CHP unit is based on the minimum annual generation requirement for that heating area. This requirement is defined as the installed capacity of each CHP belonging to that heating area, multiplied by the average CHP full load hours. DNV has considered 3000 full load hours.

The annual requirement is translated into a daily constraint, by distributing the annual minimum generation among the days of the year, based on a daily heating demand profile per country.

Min daily generation penalty – penalty for not reaching the minimum daily generation

The CHP units can deviate from the minimum daily generation by incurring a penalty. This penalty represents the replacement of the CHP generation by a gas boiler. The value consider for this penalty is 41914.6 €/GWh.

In the no-DSF scenario, district heating CHP cannot deviate from the generation requirements described above. Deviations by either not reaching or surpassing the requirement are not allowed.

The values of the abovementioned parameters are mostly based on expert knowledge and DNVs internal data.

1.1.2.9. Electrolysers

Electrolyser consumption is considered as a curtailable load, and it is modelled using the following parameters:

- Max Load [MW]: maximum hourly consumption.
- Max Yearly Consumption [GWh]

Max Load [MW]: maximum hourly consumption.

- Bid Quantity [MW]: demand bid.
- Bid Price [€/MWh]: price of the demand bid.

Electrolyser load can reduce part of its consumption when prices reach a certain activation price. Moreover, the annual consumption defined needs to be fulfilled. However, the hours when this consumption occurs are optimised by the Market model, based on the power prices and system requirements.

Maximum yearly consumption

The maximum annual consumption is determined for every country, and it is based on the REPowerEU Communication that presents a target of 10 million tons of renewable hydrogen production in Europe.

Max load – maximum hourly consumption

Max load corresponds to the maximum possible consumption from electrolysers in every hour, per country. The maximum load is the same for every hour. This value is based on the EU27 estimated Max yearly consumption and the electrolyser utilization factor. The electrolyser capacity for each county is distributed based on the ratio traditional load country/traditional load EU27.

Maximum yearly consumption

The maximum annual consumption is determined for every country, and it is based on the REPowerEU Communication that presents a target of 10 million tons of renewable hydrogen production in Europe.

Bid quantity – demand bid

Bid quantity represents the hourly consumption from electrolysers, and it is defined with the same values as Max Load. Therefore, bid quantity is the hourly consumption and also the maximum possible load shedding.
Bid price – price of the demand bid

Bid prices represents the activation price for electrolyser load curtailment. The load will be curtailed if the prices reach this specific bid price. The bid price is defined as 86.2 €/MWh, based on the cost of producing hydrogen. (RTE, 2016)

In the no-DSF scenario, electrolyser load is defined, additionally to the parameters mentioned above, with a Min Energy Year requirement. This parameter is defined with the same data as the maximum energy year property. Hence, the annual electrolyser load is fixed and cannot be curtailed, but load shifting can still occur.

The abovementioned annual targets are derived from the following sources:

Table 1.10 – Electrolysers data sources

Parameter	Source
Annual maximum/minimum consumption	(European Commission, 2022)
Hydrogen pricea	DNV, (Planbureau voor de Leefomgeving, 2020), (Thomas D. (Hydrogenics), 2016)

1.1.3. LIMITATIONS OF THE APPROACH

DNV acknowledges that the proposed approach for the quantification of market and adequacy benefits shows some limitations which are briefly presented below:

- No-DSF scenario and modelled flexible technologies: The no-DSF scenario does not provide a realistic counterfactual, but rather a reference scenario that estimates the full available potential. At the same time, due to data unavailability, DNV did not include a few relevant DSF technologies in their modelling. Therefore, the savings are the upper bound of savings considering the modelled, but not for ALL potential DSF capacity.

- Industrial DSR marginal costs: Despite more detailed insight for the Netherlands in terms of industrial process and cost details, DNV decided to exclude this from the model and instead work with the assumptions provided the above sources, that are less process-specific. Predominantly because a detailed country-by-country analysis regarding (details of) industrial processes goes beyond the scope of this research. The used figures are therefore assumed to be more conservative. For example: In the Netherlands, our previous studies indicated that there is relatively cheap DSR capacity from chlorine production. Dutch chlorine production is only a few % of what's produced in Europe, but we DNV did not find any evidence of chlorine production in other countries being used to provide DSR (at an equally low cost).

- Potential flexibility from public charging points not included, based on the assumption that most cars connected to public chargers will not be able to provide a lot of flexibility as drivers will want to 'move on'.

- Apart from EVs, other means of electric transport such as electric buses or trucks are not modelled. This is due to data unavailability.

- Investment costs are not considered for either scenario.

- The category Residential electric heating represents space heating demand and includes the electricity demand of heat pump technologies for residential and commercial buildings. Other technologies are not included in this category.

- DNV has taken a conservative approach and considered residential electric heating as a shiftable load. An RTE report (RTE, 2016) suggests that up to 50% of residential electric heating can be saved when DSF is activated, i.e. residential electric heating is not only shiftable but curtailable. The model has not incorporated the quantification insights of this report since it is based on a different technology (Joule effect heating), limited period of the year and limited geography. However, DNV acknowledges that residential heating flexibility could provide additional savings, next to the savings that are provided by load shifting according to the results.

- Due to the high electrolyser installed capacity, the electrolyser bidding price has a high impact on system prices. Although the bidding price highly depends on the characteristics from individual electrolyser plants, the model assumes a constant bidding price throughout Europe.

- The flexibility that could be provided by cooling technologies has not been considered in this analysis. This was due to limited data availability at European level.

- The renewable curtailment presented in this report refers to the curtailment due to higher available generation than load and considers the possible congestion of the interconnectors. However, congestion in national distribution and transmission networks is not considered.

1.2. Quantification of system balancing benefits

1.2.1. QUANTIFICATION APPROACH

DNV calculated the DSF balancing energy benefits based on the different marginal costs for eligible balancing technologies at EU level. To do so, this approach was followed:

Step 1 consisted of data collection, DNV collected information on reserve volumes, reserve capacities and marginal costs. The calculated total activated balancing reserves for EU 27 in 2021 (these are assumed to be the same in 2030). The total activated reserves are extracted from ENTSO-E (ENTSO-E, 2022) and are summarised in the table below:

Reserve	Volumes 2021 (GWh)
aFRR down	-7735.64
aFRR up	8504.27
mFRR down	-10746.07
mFRR up	8504.27
RR down	-17689.66
RR up	13344.83

The reserve capacities were estimated based on a sample of requirements from 9 countries with relative lower (Belgium) and higher (France) reserve requirements (ENTSO-E, 2022), (TERNA, 2020). The resulting range of required balancing capacity for EU 27 is shown in the table below:

Reserve	Volumes 2021 (GWh)	Volumes 2021 (GWh)
	LOW RANGE	HIGH RANGE
aFRR (upward/ downward)	12465	18450
mFRR (upward/ downward)	29760	45300
RR(upward/ downward)	6500	8500

The marginal costs for all technologies, depending on downward or upward reserve, are summarised in the tables below:

DOWNWARD	aFRR	mFRR	RR	Price €/ MWH	Calculation/Source
EV	X	X		2.9	Based on compensation to consumer that offers flex in ancillary services (Vandebron, 2017) (Jedlix, 2022)
Heatpump	X	X		2.9	Based on compensation to consumer that offers flex in ancillary services (Vandebron, 2017) (Jedlix, 2022)
EV – V2G	X	X	X	9.7	Average electricity price 2030 (output from market model) multiplied by round-trip efficiency loss (13%)
Battery FTM	X	X	X	9.7	Same as above
Battery BTM	X	X	X	14.7	Same as above
CCGT	X	X	X	74.7	Same as upward BatterLost revenue based on average market price (output from market model) and saved operational cost (gas price/efficiency + emission cost = 36.1 €/MWh). Gas, efficiency and emission prices are based on the assumptions taken in the market model for 2030M
Wind curtailment	X			74.7	Cost of lost revenue based on average electricity price in 2030 (output from the market model)
PV curtailment	X			74.7	Same as above
Pumped hydro		X	X	99.6	Average electricity price in 2030/efficiency of pumping (75%)
Electrolyzers		X	X	100.4	Average electricity price in 2030/efficiency (67.7%)

UPWARD	aFRR	mFRR	RR	Price €/ MWH	Calculation/Source
EV	X	X	X	3	Same as downward EV
Heatpump	X	X	X	3	Same as upward heat pump
Pumped hydro	X	X	X	6	Based on LCOE (C. Garcia Mazo, 2020)
EV – V2G	X	X	X	10	Same as upward V2G
Battery FTM	X	X	X	10	Same as upward Battery FTM
Battery BTM	X	X	X	10	Same as upward Battery BTM
CCGT	X	X	X	60	Based on gas price (25.3 €/MWth – market model), gas energy density, efficiency (60%), emissions of gas (201.9 kg/MWh LHV gas) and emission cost (53 €/ton)
CHP	X	X	X	75	Same as above but considering 48% efficiency.
Electrolyzers		X	X	86	Same as cost of hydrogen in Appendix A – section 1.1.2.9
Gas turbines	X	X	X	120	Same as CCGT but considering 30% efficiency.
Industrial DSR – 24 hr		X	X	207	Equivalent to Variable Operation & maintenance cost of this flexibility. See Appendix 1- section 1.1.2.1.
Industrial DSR – 4 hr		X	X	323	Equivalent to Variable Operation & maintenance cost of this flexibility. See Appendix 1- section 1.1.2.1.
Industrial E-boiler		X	X	500	Equivalent to bid price. See Appendix 1 – section 1.1.2.6.
Industrial DSR – 8 hr		X	X	500	Equivalent to Variable Operation & maintenance cost of this flexibility. See Appendix 1- section 1.1.2.1.
Industrial DSR – 1 hr		X	X	1000	Equivalent to Variable Operation & maintenance cost of this flexibility. See Appendix 1- section 1.1.2.1.
Industrial DSR – 2 hr		X	X	1097	Equivalent to Variable Operation & maintenance cost of this flexibility. See Appendix 1- section 1.1.2.1.

Step 2 consisted of building the technology merit order for the provision of balancing energy in 2030 per scenario (DSF and no-DSF scenario).

The DSF scenario included all technologies that are considered as DSF in the modelling exercise (e.g. smart charging, batteries behind the meter, electric heating, industrial DSR, etc) as well as other flexible technologies (electrolysers and front of the meter BESS) and traditional balancing reserve providers (gas turbines, gas power plants, hydro power, etc.)

The capacities used to build the merit order were derived from the calculated DSF power in the previous section, as well as the input generation capacities in DNV's power market model for 2030.

An example of merit order is presented in Figure 12. The figure includes the technology merit order for providing upward aFRR energy for each scenario. The green band represents the required aFRR capacity for all EU. Figure 13 zooms in the merit order to show more details in the relevant capacity range. It can be observed that all aFRR upward capacity can be provided by hydro energy in the no-DSF scenario (at around 6 €/MWh) and by residential DSF in the DSF scenario (at around 3 €/MWh).

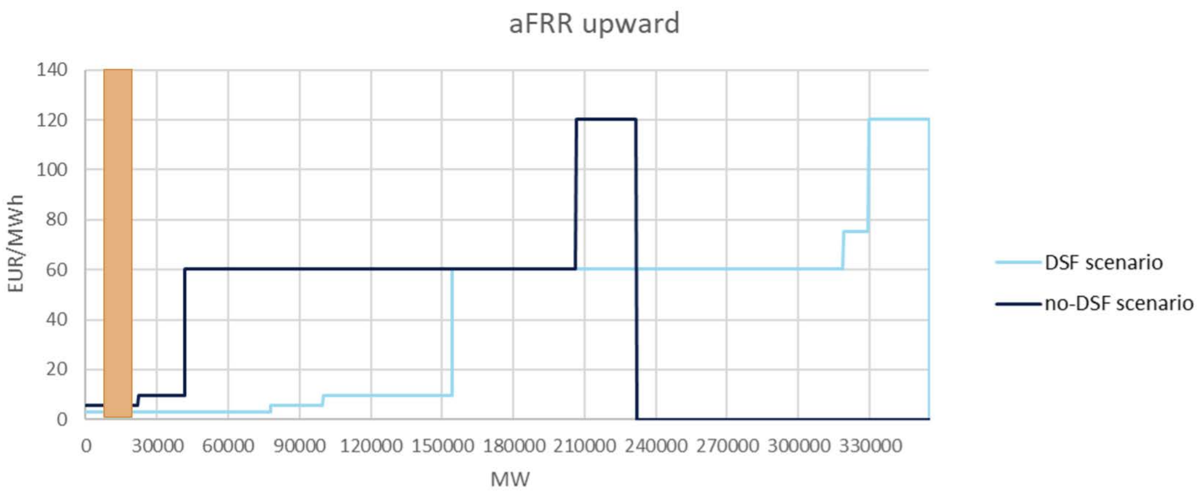


Figure 12 – Upward aFRR merit order (all capacity)

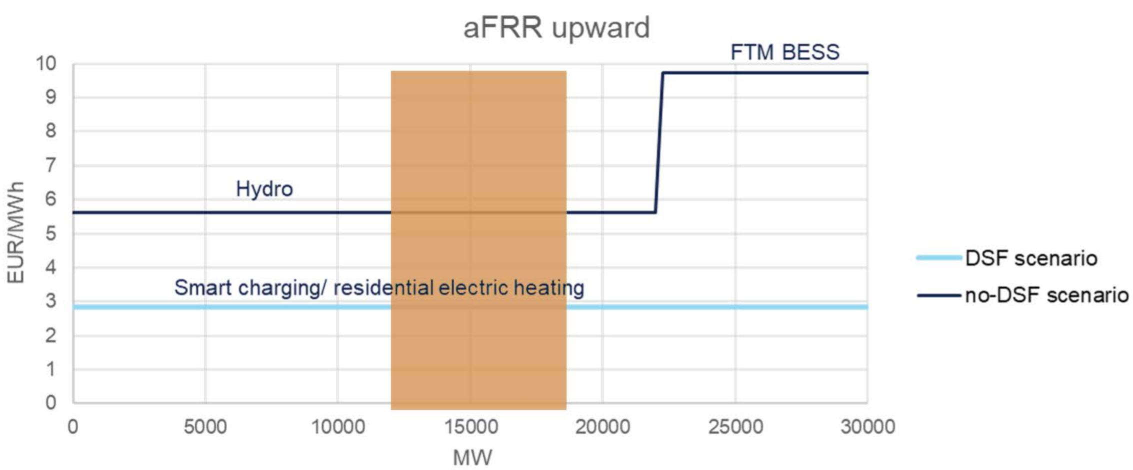


Figure 13 – Upward aFRR merit order (zoom-in)

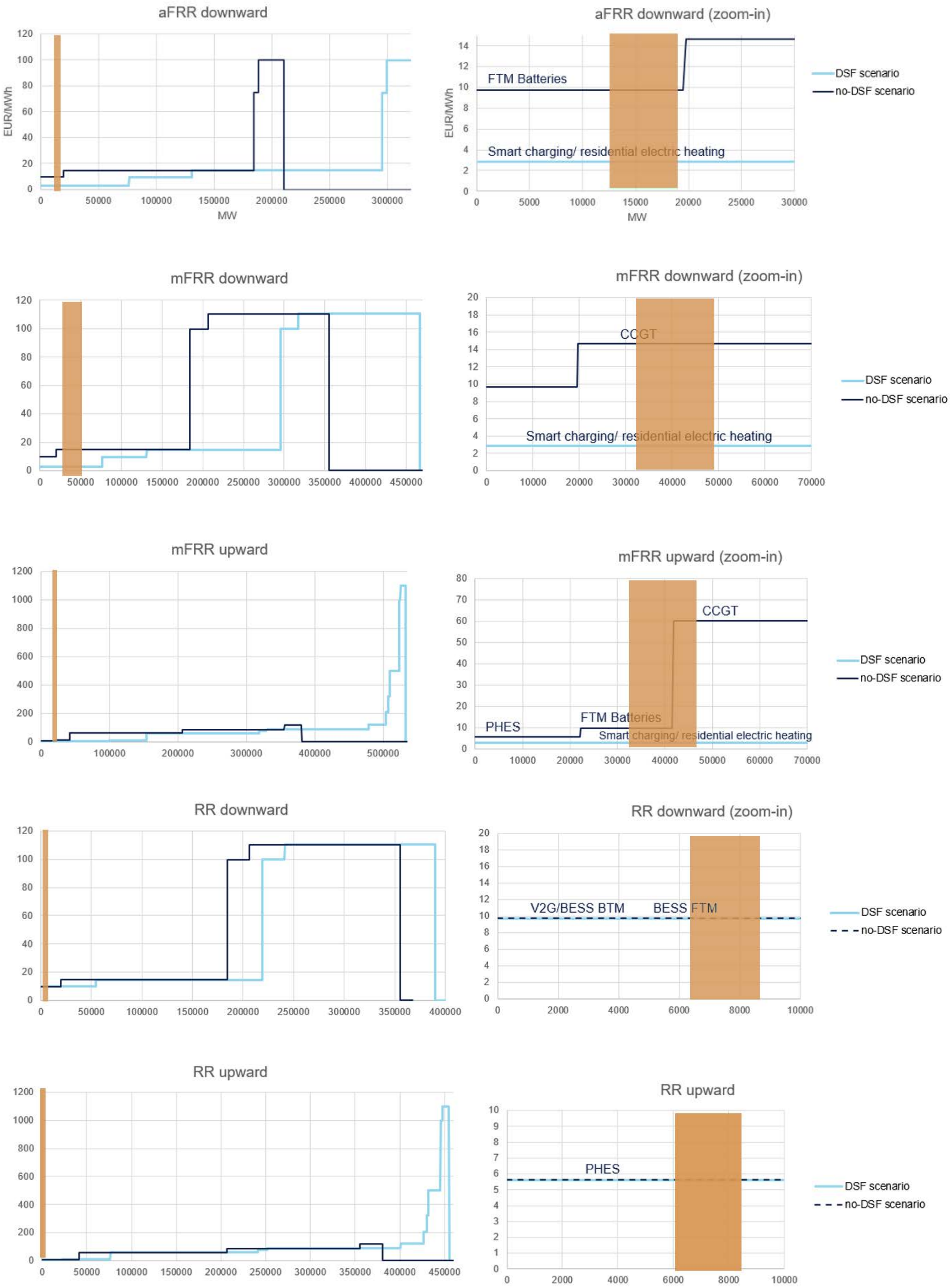


Figure 14 – Merit order for all balancing energy services

Based on the merit order and the required capacities, the cut out marginal costs for balancing energy is determined. For some products there is a range of marginal costs because the reserve required capacity band intersects with more than one technology. The results are presented in the table below:

UPWARD	Marginal price 2030 DSF (€/MWh)		Marginal price 2030 no-DSF (€/MWh)	
	Low	High	Low	High
aFRR down	2.85	2.85	9.72	9.72
aFRR up	2.85	2.85	5.62	5.62
mFRR down	2.85	2.85	14.66	14.66
mFRR up	2.85	2.85	9.72	60.07
RR down	9.72	9.72	9.72	9.72
RR up	5.62	5.62	5.62	5.62

Finally, **step 3** consisted of calculating the balancing costs for all reserve services based on the merit orders in **step 2.** The DSF benefits were calculated as the difference between the no-DSF scenario balancing costs and the DSF scenario balancing costs. The results are summarised below:

UPWARD	DSF balancing benefits (million €)	
	Low	High
aFRR down	53.1	53.1
aFRR up	23.6	23.6
mFRR down	127.0	127.0
mFRR up	58.4	486.6
RR down	0.0	0.0
RR up	0.0	0.0
TOTAL	**262.0**	**690.2**

1.2.2. LIMITATIONS OF THE APPROACH

DNV acknowledges that the proposed approach for the quantification of system balancing benefits shows some limitations which are briefly presented below:

- The balancing requirements at European level are calculated as a sum of country-specific balancing-capacity requirements. DNV does not quantify the synergies of having a unified European market and how that affects the balancing requirements.

- The quantification assumes that there is enough interconnection capacity available between bidding zones, so all flexibility is available to all systems.

- The merit order is built based on marginal costs of the different technologies only. Other costs such as opportunity costs (e.g. the missed revenue for not selling their flexibility in other markets such as congestion management) are not included.

- The required balancing volumes in 2030 are considered to be the same as 2021.

1.3. Quantification of grid infrastructure benefits

1.3.1. DESKTOP RESEARCH

DNV has conducted desktop research on the infrastructural benefits that DSF may enable. The research looked for studies that have quantified the benefits related to delayed or deferred grid reinforcements by 2030, preferably published in the last 5 years and focusing in one or multiple countries for the EU 27+ area. Table 1.1 provides a selection of the studies reviewed by DNV for this desktop research.

Table 1.11 – Selection of studies reviewed by DNV for the desktop research on DSF infrastructural benefits

Reference	Author	Title	Year of publication
(RTE, 2020)	RTE	Cadrage des hypothèses sur les gisements de flexibilité de la demande	2020
(Energy Union Choices, 2017)	Energy Union Choices	Cleaner, Smarter, Cheaper	2017
(European Commission, 2017)	European Commission	Mainstreaming RES Flexibility Portfolios	2017
(Aurora, 2021)	Aurora	CO2 free flexibility options for the Dutch power system	2021
(ECN, Alliander, 2017)	ECN, Alliander	The supply of flexibility for the power system in the Netherlands, 2015-2050	2017
(Elia, 2021)	Elia	Adequacy and flexibility study for Belgium 2022-2032	2021
(RTE, 2021)	RTE	Energy pathways to 2050	2021
(Triple, 2015)	Triple	The balance of power –flexibility options for the Dutch electricity market	2015
(European Climate Foundation, 2010)	European Climate Foundation	Roadmap 2050	2010
(Arthur D. Little, 2020)	Arthur D. Little	Distributed flexibility: the next pool of value, 2020	2020
(DNV GL, 2021)	DNV GL	Samhällsekonomiska kostnader och nyttor av smarta elnät	2021
(DNV GL, 2019)	DNV GL	Kostnader i strømnettet gevinster ved koordinert lading av elbiler	2019
(Carbon Trust, 2021)	Carbon Trust	Flexibility in Great Britain	2021
(Eurelectric, 2021)	Eurelectric	Connecting the dots: distribution grid investment to power the energy transition	2021
(E-Bridge, 2019)	E-Bridge	Wirtschaftlicher Vorteil der netzdienlichen Nutzung von Flexibitaet in Verteilnetzen	2019

The desktop research has shown that very little literature is currently available on the quantification of infrastructural benefits in terms of delayed or deferred grid investments that DSF may enable. On the one hand, the interpretation of the concept of flexibility in many studies is not consistent with the one used for this evaluation. Flexibility is also often sought on the generation side of the system rather than on the demand side, for instance by means of CCGT gas turbines. When focusing on DSF, many studies primarily quantify of the flexibility potential of one or multiple technologies without investigating the potential infrastructural benefits. Others provide a very high-level definition of DSF, for instance 20% of the peak demand that can be shifted throughout the day. On the other hand, the results of those studies that quantify the benefits may not be applicable to the task at hand. For example, some studies quantify the benefits of additional flexible technology capacity rather than the benefits of the use of flexible technologies. Other results are too case-specific or grid-specific to be scaled at EU level.

Overall, DNV acknowledges the scarcity of studies on the infrastructural benefits of DSF. It was, therefore, impossible to pursue the original plan of estimating the infrastructural benefits in a Fit for 55 scenario based on existing studies based on either country-specific or EU 27 grid simulations.

DNV has, therefore, defined a two-phase approach to estimate the infrastructural benefits at EU level relying on the limited number of relevant studies. Next, the approach is detailed, and its main limitations are discussed.

1.3.2. QUANTIFICATION APPROACH

DNV approach for the quantification of infrastructural benefits focuses on distribution grid investments and it is structured in two phases: a top-down phase to estimate the required investments per country and a bottom-up phase to estimate the potential savings at EU 27 level. The approach strongly relies on the figures presented in the (Eurelectric, 2021) study on the required distribution grid investments in EU 27+ to enable the energy transition and in the (E-Bridge, 2019) study on the benefits of the grid-friendly use of flexibility in German distribution networks. The study (Eurelectric, 2021) assesses DSO investments requires for enabling the energy transition in Europe and develops policies and recommendations. The study estimates 375 – 425 billion € of power distribution grid require investments between 2020 and 2030 in EU 27+UK. These figures are extrapolated based on information provided by the DSOs of 10 countries accounting for about 70% of EU electricity demand. The required investments are divided into four main areas, the largest being due to electrification and renewables, and eight main investment drivers. DNV refers to this study to estimate the required investments in distribution grids by 2030 in a Fit for 55 scenario based on three main drivers, namely final electricity demand, electric vehicles, and RES capacity connected to distribution grid.

The study (E-Bridge, 2019) quantifies the economic potential of flexibility for congestion management in the German distribution grid for the year 2035 and determines the possible benefits in terms of deferral of grid expansion investments through a better utilisation of the grid. The study relies on thousands of grid simulations and shows that, while the increase in flexibility used purely for the benefit of the market/system leads to an increasing need for grid expansion, a grid-friendly use of flexibility may reduce the required investments in German distribution grid by 55%. DNV refers to this study to estimate the potential savings in grid investments at EU 27 level thanks to a grid-friendly use of demand side flexibility.

The approach proposed by DNV is shown in Figure 15.

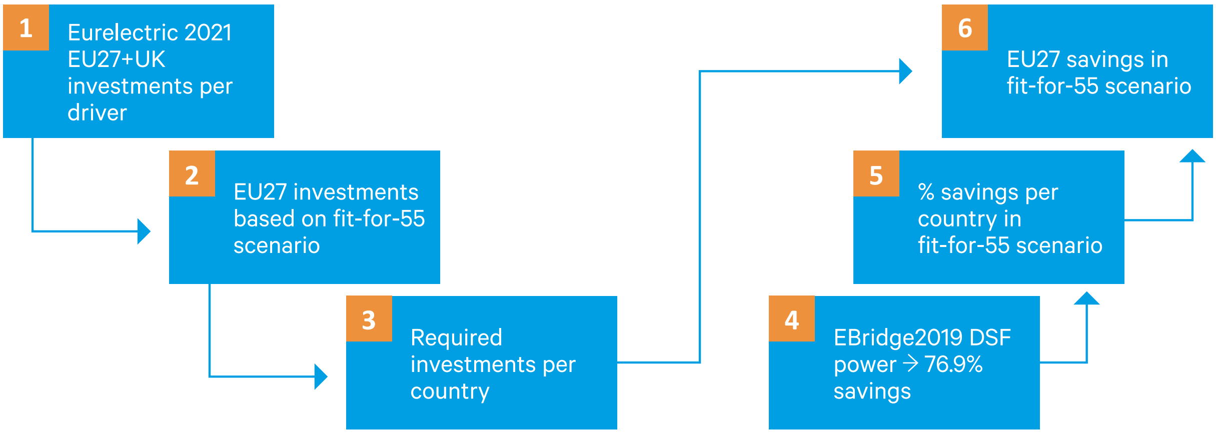


Figure 15 – DNV's approach for quantification of infrastructural benefits

The first phase of the DNV approach is top-down and estimates the required investments in distribution grid between 2023 and 2030. It uses the figures from **(Eurelectric, 2021)** on the investments in distribution grids due to electrification and renewables and its breakdown per relevant investment drivers, namely, electrification of buildings and industry, electrification of mobility, and emission-free generation.

The bottom-up phase estimates the infrastructural benefits in 2030 in a Fit for 55 scenario thanks to DSF. It uses the figures from (E-Bridge, 2019) on the potential savings in investments when DSF is operated in a grid-friendly way rather than in a market/system friendly way. Based on the market simulation results, the savings presented by (E-Bridge, 2019) for German distribution networks are scaled and applied to the other countries. Finally, the total EU 27 savings are calculated.

1.3.2.1. Top-down phase

The top-down phase consists in the following steps:

1 *Estimate of the investment per unit of driver based on* **(Eurelectric, 2021)**. The study **(Eurelectric, 2021)** estimates that the electrification of the energy demand and the increase in renewable capacity will require 180–210 billion € investments in distribution grids between 2020 and 2030. The main drivers are the following: increase in final electricity demand, electric vehicles, and emission-free generation. The study expects an increase in total power demand between 2017 and 2030 of 732 TWh, which is responsible for 70–80 billion € investment. Additionally, the number of EVs in 2030 is expected to reach 50–70 million vehicles and is responsible for 25–35 billion €. Furthermore, the renewable capacity connected to distribution grids is estimated to increase by 360 GW between 2017 and 2030, requiring 85–95 billion €. The impact of each driver on the total required investments is summarised in Table 1.12.

Table 1.12 – Impact of investment drivers on the required investments in distribution grid due to electrification of the energy demand and increase in renewable capacity according to (Eurelectric, 2021)

Driver	Quantifying parameter	Investment per unit of driver
Electrification of demand	Increase in total demand	0.096–0.109 bn/TWh
Electrification of mobility	Number of EVs	0.5 bn/million
Emission-free generation	RES capacity addition to distribution grids	0.236–0.264 bn/GW

2 *Estimate of required investments in distribution grids in EU 27 between 2023 and 2030 in Fit for 55 scenario.* Using the DNV's European Power Market Model for 2023 and the 2030 model developed for this study, DNV estimates the values of investments associated with the main investment driver identified at the previous step. The share of solar PV and wind capacity connected to the distribution grid is calculated using the figures provided for ten countries by (Eurelectric, 2021). For those countries for which the study does not report a figure, the share of countries with comparable area is used. Table 1.13 summarizes the results. The total required investments in distribution grids in EU 27 between 2023 and 2030 are between 253.1 and 282.5 billion €.

Table 1.13 – Required investments in distribution grid between 2023 and 2030 in Fit for 55 scenario

Driver	Quantifying parameter	Quantity	EU 27 Fit for 55 investment
Electrification of demand	Increase in total demand	1352 TWh	129.3–147.8 billion
Electrification of mobility	Number of EVs	61 million	30.5 billion
Emission-free generation	RES capacity addition to distribution grids	395 GW	93.3 – 104.3 billion

3 *Estimate required investments in distribution grids per country between 2023 and 2030.* The estimated investments at EU 27 level are distributed across countries using three metrics that quantify the extent to which each country contributes to the investment drivers at European level previously identified. Namely, the metrics represent the share of increase in total demand, the share in EVs, and the share of additional RES capacity. The range of investments 253.1 – 282.5 billion € is, hence, distributed cross countries using these metrics. As a result, six values are obtained per country and a range of investment is defined. See box below for an illustrative example.

EU 27 investments:
253.1 – 282.5 billion €

Country X:

- **Share in increase in total demand:** 3% (40.6 TWh)
- **Share in EVs:** 1.8% (1.1 million)
- **Share in additional RES capacity:** 4% (15.9 GW)

Country X range of investments: 4.7 – 11.4 billion

1.3.2.2. Bottom-up phase

The bottom-up phase consists of the following steps:

4 *Calculate relation between available flexible capacity and savings.* The study (E-Bridge, 2019) estimates the flexible capacity coming from electric heat applications at 6.5 GW, from EVs at 10.5 GW, and from small storage at 5.5 GW. Additionally, it estimates that residential, industrial, and trade and commerce traditional load can provide 12%, 4.8%, and 21% of flexibility, respectively. Since the study reports no figure of the peak load and it was conducted in 2019, the German 2035 estimate for peak load according to the 2019 update of the DNV's European Power Market Model is used as a reference, i.e., 133 GW of peak demand in 2035. Averaging the flexibility ratios of traditional load reported by the study, it can be assumed that 12.6% of the peak demand is flexible. In total, the calculated available flexible capacity by 2035 is 39.3 GW, which results from adding up flexibility of EVs, storage, e-heating and flexible traditional load.

Therefore, it is calculated that a flexible capacity to peak demand of 29.5% leads to 76.9% savings.[18]

5 *Estimate savings in % per country.* The potential percentage savings are calculated per country based on:

- Available flexible capacity;[19]
- the relation derived at step 4, i.e., a flexibility capacity to peak load ratio of 29.5% leads to 76.9% savings; and
- peak demand in 2030.

The savings in % are calculated per country as follow:

$$savings\% = \frac{availableFlexCapacity}{peak\ load} \quad \frac{76.9\%}{29.5\%}$$

See box below for an illustrative example.

Country X – market simulation output:

- **Available flexible capacity:** 2 GW
- **Peak load:** 9.9 GW

Step 5:

- **Country X savings in %:** 52.6% (2/9.9 * 76.9%/29.5%)

18. This percentage of savings only accounts for savings on low voltage and medium voltage distribution grids
19. DSF flexible power is derived from the results of section 2 – quantification of DSF in 2030. The grid benefits quantification approach is based on the upward flexible power.

6 *Estimate savings at EU 27 level.* Based on the estimated savings in % per country according to step 5, the potential range of savings in each country is calculated. Finally, the potential infrastructural savings in distribution grid investments at EU 27 level between 2023 and 2030 thanks to grid-friendly DSF are calculated by summing up the country-specific values.

The savings at EU 27 level between 2023 and 2030 are estimated at 77.6–203.6 billion €, which corresponds to annual savings of 11.1 and 29.1 billion €.

1.3.3. LIMITATIONS OF THE APPROACH

DNV acknowledges that the proposed approach for the quantification of infrastructural benefits shows some limitations, which are briefly presented below:

- The relation between DSF power and investment savings is neither derived from literature nor from grid model simulation results, but rather calculated based on data derived from two different sources, namely, (E-Bridge, 2019) and DNV's European Power Market Model 2019 update.

- The quantified investments and savings refer to the distribution grid only. Investments required in transmission grids are not quantified.

- The quantified investments account for integration of new (electrified) loads and RES capacity only. Other investments, such as digitalisation and smart meter roll out, are not calculated.

- The approach does not take into account the differences in the current status of development across distribution grids. For example, those countries still mostly relying on gas-based heating systems might face larger costs to enable distribution grids to cope with increasing heat pump capacity and electric heating load than those countries already largely relying on electric heating systems.

- The approach does not take into account the differences across countries regarding voltage level in the distribution grid. The approach assumes that the savings are on low voltage and medium voltage distribution grid.

- The investment costs per driver are assumed to be linear while they may strongly depend on other factors, such us the current status of the distribution grids.

APPENDIX B – References

Arthur D. Little. (2020). *Distributed flexibility: the next pool of value, 2020.*

Aurora. (2021). *CO2 free flexibility options for the Dutch power system.*

BMWK. (2022). Germany, Denmark, Netherlands and Belgium sign €135 billion offshore wind pact. Retrieved from: https://www.bmwk.de/Redaktion/DE/Downloads/Energie/20220518-declaration-of-energy-ministers.pdf?__blob=publicationFile&v=10

California Institute of Technology. (2021). ACN-Data. Retrieved from https://ev.caltech.edu/dataset

Carbon Trust. (2021). *Flexibility in Great Britain.*

DNV. (2021)**.** Energy Transition Outlook (ETO) 2021.

DNV GL. (2019). *Kostnader i strømnettet gevinster ved koordinert lading av elbiler.*

DNV GL. (2021). *Samhällsekonomiska kostnader och nyttor av smarta elnät .*

EASE, D.-E. (n.d.). *EMMES 6.0.* Retrieved 2022, from https://ease-storage.eu/publication/emmes-6-0-june-2022/

E-Bridge. (2019). *Wirtschaftlicher Vorteil der netzdienlichen Nutzung von Flexibitaet in Verteilnetzen.*

ECN, Alliander. (2017). *The supply of flexibility for the power system in the Netherlands, 2015-2050.*

ElaadNL. (2020). Open EV charging datasets. Retrieved from https://platform.elaad.io/analyses/index.php?url=ElaadNL_opendata.php

Elia. (2019). Adequacy and flexibility study for Belgium 2020-2030.

Elia. (2021). *Adequacy and flexibility study for Belgium 2022-2032.*

Energy Union Choices. (2017). *Cleaner, Smarter, Cheaper.*

ENTSO-E. (2020). Ten-Year Development Plan 2020.

ENTSO-E. (2021). European Resource Adequacy Assessment (ERAA).

ENTSO-E. (2022). *Balancing report.*

ENTSOG and ENTSO-E. (2022). Ten-Year Network Development Plan (TYNDP) 2022- Scenario Report- Version April 2022.

Eurelectric. (2021). *Connecting the dots: distribution grid investment to power the energy transition.*

European Climate Foundation. (2010). *Roadmap 2050.*

European Commission . (2021). *'Fit for 55': delivering the EU's 2030 Climate Target on the way to climate neutrality.*

European Commission. (2017). *Mainstreaming RES flexibility portfolios.*

European Commission. (2022). REPowerEU Plan.

European Commission DG Energy. (2016). *Impact assessment study on downstream flexibility, price flexibility, demand response & smart metering. European Commission DG Energy.*

European Commission, Directorate-General for Energy. (2022). *Best practices and assessment of regulatory measures for cost-efficient integration of electric vehicles into the electricity grid.* Publications Office of the European Union.

eurostat. (2020, 07 10). Retrieved from https://ec.europa.eu/eurostat/documents/2995521/11081093/3-10072020-AP-EN.pdf/d2f799bf-4412-05cc-a357-7b49b93615f1

Jedlix. (2022). Retrieved from https://www.jedlix.com/nl/mountox-landingspage/

LAZARD. (2020). *Lazard's Levelized Cost of Energy Analysis - version 14.0.*

Planbureau voor de Leefomgeving. (2020). *EINDADVIES BASISBEDRAGEN SDE++ 2020.*

RTE. (2016). *ÉVALUATION DES ÉCONOMIES D'ÉNERGIE ET DES EFFETS DE BORD associés aux effacements de consummation.*

RTE. (2020). *Cadrage des hypothèses sur les gisements de flexibilité de la demande.*

RTE. (2021). *Energy pathways to 2050.*

Ruhnau, O. H. (2019). Time series of heat demand and heat pump efficiency for energy system modeling.

TERNA. (2020). *Terna report on Balancing in accordance with Article 60 of COMMISSION REGULATION (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.*

Thomas D. (Hydrogenics), M. D. (2016). *POWER TO GAS Roadmap for Flanders.*

Triple. (2015). *The balance of power –flexibility options for the Dutch electricity market.*

UK Government. (2022). Electric vehicle charging transaction. Retrieved from https://www.data.gov.uk/dataset/16c7326b-57fe-4803-88f8-9286c387f68a/electric-vehicle-charging-transactions

Vandebron. (2017). Retrieved from Slim laden: hoe werkt dat?: https://vandebron.nl/blog/slim-laden-hoe-werkt-dat

Platinum Partners

Eaton is an intelligent power management company dedicated to improving the quality of life and protecting the environment for people everywhere. We are guided by our commitment to do business right, to operate sustainably and to help our customers manage power – today and well into the future. By capitalizing on the global growth trends of electrification and digitalization, we're accelerating the planet's transition to renewable energy, helping to solve the world's most urgent power management challenges, and doing what's best for our stakeholders and all of society.

Enel is a multinational energy company and one of the world's leading integrated utility within the energy sector. We are present in more than 40 countries across five continents, generating energy with a total installed capacity of around 92 GW (of which around 55 GW of renewables capacity), selling electricity and gas and distributing electricity across a network spanning more than 2.2 million km. With almost 76 million end users worldwide, we are the biggest networks operator, we manage the largest customer base in the utilities sector with around 70 million retail customers and we are one of Europe's leading energy companies by installed capacity.

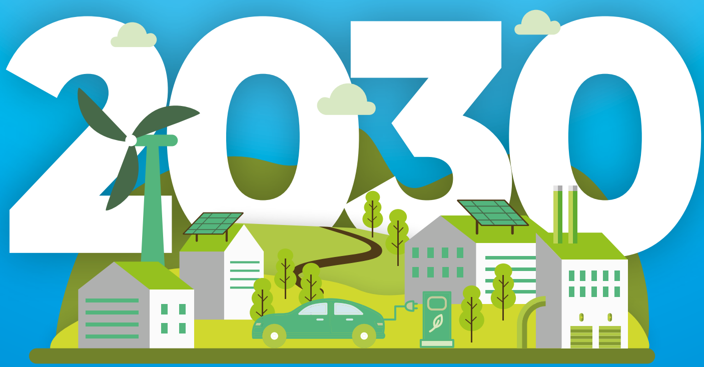
The Enel Group counts on a workforce of more than 67,000 people from around the world and its foundations are based on the values of Responsibility, Innovation, Trust and Proactivity.

Gold Partner

As a major player in energy transition, the EDF Group is an integrated energy company active in all businesses: generation, transmission, distribution, energy trading, energy sales and energy services. EDF group is a world leader in low-carbon energy, having developed a diverse production mix based mainly on nuclear and renewable energy (including hydropower). It is also investing in new technologies to support energy transition. EDF's raison d'être is to build a net zero energy future with electricity and innovative solutions and services, to help save the planet and drive well-being and economic development. The Group is involved in supplying energy and services to approximately 38.5 million customers , of whom 29.3 million in France. It generated consolidated sales of €84.5 billion in 2021. EDF is listed on the Paris Stock Exchange.

Silver Partner

smartEn
Smart Energy Europe



DNV