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## NEP 2.0

A new grid development plan for the future

TENNET  
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A new grid development  
plan for the future

Copenhagen  
Economics



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## **PREFACE**

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The German grid development plan for electricity (NEP) sets the frame for future investments in the German transmission grid infrastructure. The NEP is a joint plan by the four transmission system operators (TSOs) in Germany, which are legally obliged to preparing and submitting the NEP to the regulator. The NEP contains a range of scenarios of the future energy-economic development and their consequences for the German transmission grid. The large-scale expansion of renewable energy in particular is an important driver for grid expansion. In preparation of the NEP, the TSOs identify potential areas of stress in the system and define the investments needed to relieve the stress. The NEP is therefore the tool for assessment and approval of future grid investments.

While the NEP has been a welcome turning point for German grid planning when introduced in 2012, stakeholders are becoming increasingly worried whether the NEP is fit for a future that will be characterised by digitalisation and 60 to 100 per cent electricity from renewable sources.

Against this backdrop, TenneT has asked Copenhagen Economics to investigate whether the NEP is fit for the future, and how potentially to improve the NEP process.

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## EXECUTIVE SUMMARY

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The extensive transformation of the energy system taking place in Germany and surrounding countries has sharply increased the need for grid infrastructure in Germany. The key driver is the growth of intermittent renewable energy sources (wind and solar), in particular wind power far from consumers in conjunction with the parallel decline of stable baseload production closer to consumers (conventional power plants and nuclear power plants).

The introduction of the common German Grid development plan (NEP), to which the Energy Act (*Energiewirtschaftsgesetz*, EnWG) forms the legal framework, has been a timely and successful factor in improving the functioning of the German grid planning. The plan has paved the way for an expansion of annual grid investments and has therewith successfully supported the first phase of the *Energiewende*, the energy transition in Germany. Grid investments amounted to about EUR 600 million annually before the first NEP (2007-2011) and increased constantly after 2011 towards roughly EUR 2 billion annually since 2015.

The measures that are today listed in the German Federal Requirements Plan Act (*Bundesbedarfsplangesetz*, BBPlG) and the Power Grid Expansion Act (*Energieleitungsbaugesetz*, EnLAG) are the absolute minimum of investments necessary for the transmission grid to be able to take on large amounts of renewable energies. The measures listed in the BBPlG and the EnLAG are therefore no-regret measures and must be the starting point for all further investments in the future grid planning 2.0. However, it becomes more and more clear that the current NEP approach might not be fit for the continued and massive transformation of the German energy system over the coming decades.<sup>1</sup> In our evaluation, the key weaknesses in the current NEP approach are the following related issues, which is likely to – without a reform of the approach – have a negative effect on the future grid planning:

*First*, the NEP bases its identification of investment needs on the premise to avoid bottlenecks (nearly completely) in a single year (in the latest NEP, 2030).

*Second*, costs or benefits associated with potential bottlenecks in years prior to or after 2030 are, except for one scenario looking slightly further ahead into the year 2035, not factored into investment criteria.

*Third*, the assessment is based on scenarios with limited variation in the key drivers for investment needs – such as flexible demand, storage, geographical location and concentration of demand – during the very long lifetime of the grid assets. We would stress risks associated with grid capacity

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<sup>1</sup> Studies by Agora Energiewende (2018) "Toolbox für die Stromnetze" and Agora Energiewende (2017) "Optimierung der Stromnetze" for example point out weaknesses in the current grid planning approach.

becoming underutilised in the coming decades. This risk is closely linked to a possible rapid maturing of technologies solving bottlenecks and providing flexibility at lower costs than traditional grid investments (the “stranded asset” discussion).

*Fourth*, too rigid rules determine how TSO can deal with bottlenecks which might both block grid investments with higher expected economic viability than alternatives as well as force grid investments when alternatives are less costly.

*Fifth*, the current NEP is very resource consuming and recurs every two years. It has arguably too much focus on running very detailed grid models to calculate bottlenecks in a single year despite the fact that the scenarios used to assess investment needs often have limited variation relative to the former round for the same year.

To remedy those issues, we propose a reform package with three key elements. In addition, a smooth transition from the current NEP to the NEP 2.0 is important.

**A more robust evaluation of grid investments in a longer-term perspective.** Each investment should be based on net-value approach, be compared to alternatives and not be based on the bottleneck-free grid. Costs and benefits are to be measured ideally over the lifetime of the asset, not just a single year.

**Explicit treatment of longer term investment risks and opportunities.** The scenarios underpinning the evaluation should be based upon a more realistic variation of the key drivers behind investment needs, not the least the increasing economic maturity and scalability of alternatives to grid investments. Grid investment that have high net-value across a large range of plausible scenarios should be prioritised in the NEP.

**More flexible and comprehensive approach to grid planning.** We suggest changing the frequency of the NEP. Currently, a NEP is produced every second year; we suggest to produce a thorough, formal NEP with thorough analyses and risk assessments every fourth or fifth year, or when significant changes in the main drivers for investments occur. In between those years, we suggest to produce a lighter monitoring report (annually or bi-annually) to assess major changes in the assumptions behind the investment needs. Based on this monitoring report, the TSOs should be allowed to move marginal investment projects up (towards submission for approval) or down (i.e. not prioritised) a the (not yet existing) prioritisation list in the NEP. The NEP will also provide insight into the long-term grid investment costs associated with alternative scenarios; this insight can be a very valuable input to the overall energy policy discussion, and can for example help achieving the *Energiewende* at the lowest possible socio-economic costs.

**A smooth transition from the current NEP 1.0 to the reformed NEP 2.0.** The momentum generated by the current NEP 2030 should be maintained, which is why we suggest finalising the current NEP as planned. The TSOs can on the basis of the current approach calculate and assess the need for new grid investments until the beginning of 2019. Some new elements such as suggestions from this study could potentially already be included. However, on the whole, the assessment of the need for investment will be done as usual in the past, and will be based on current principles. In parallel, preparation for the new NEP 2.0 should start now and eventually lead to principles,

legislation and guidelines being re-designed so that they can support the NEP 2.0 from 2020 onwards.

Our analysis of weaknesses and the practical implementation of our recommendations is mapped out in more detail in the main report.

## BACKGROUND

# NEP 2.0 – NEW CHALLENGES FOR THE FUTURE’S GRID PLANNING

The extensive transformation of the power sector that has taken place in Germany and Europe over the last decade has sharply increased the need for investments in grid infrastructure in Germany. The transformation has been driven by the growth of intermittent renewable energy sources, in particular wind power located far away from consumers, and by the decline of stable traditional base-load energy sources, often located close to consumers. Therefore, production is becoming more volatile and transmission distances between energy sources and consumers are growing. Both features have strongly increased the need for investments in transmission capacity in Germany.

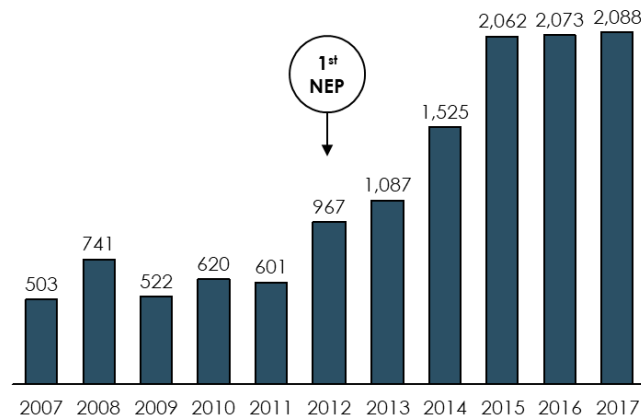
The introduction of the German grid development plan for electricity (NEP), which has its legal basis in the Energy Act (*Energiewirtschaftsgesetz*, EnWG), has for several reasons been timely and successful turning point for German grid planning. *First*, NEP has established a thorough coordination framework for the four German TSOs that enable them to reap synergies and has in general strengthened a federal as opposed to a Länder perspective on grid management. *Second*, NEP has made it possible to introduce large nation-wide HVDC corridors as an alternative to continued local reinforcing of smaller scale AC lines. *Third*, the most recent NEP has also introduced some options for innovative projects in addition to traditional grid solutions, such as load flow management measures. *Fourth*, NEP has introduced a clearer regulatory approval process, where the approved projects have been trans-posed into law ensuring commitment from national authorities.<sup>2</sup>

Arguably, these features of the NEP have been key factors in the significant expansion of annual grid investments from around EUR 600 million before 2010 to about EUR 2 billion from 2015 and onwards; see Figure 1.

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<sup>2</sup> The national commitment does not however necessarily apply to the local authorities approving project implementation.

**Figure 1**  
**Increasing investments into the German transmission grid in the past ten years**  
Investments in mio. EUR



Note: Preliminary data for 2017. Investments of all 4 TSOs accumulated.

Source: statista (2018) 'Investitionen und Aufwendungen für die Netzinfrastruktur der Übertragungsnetzbetreiber in Deutschland in den Jahren 2007 bis 2017'. link: <https://de.statista.com/statistik/daten/studie/168146/umfrage/investitionen-in-die-stromnetze-der-uebertragungsnetzbetreiber-seit-2007/>

This is only a start. In total in the last ten years, Germany has invested in transmission grid at a level around EUR 12 billion. A multiple of that sum will be needed in the coming decades in order for the transmission grid to meet the requirements of the new German power landscape.

These estimates are however already outdated if the ambitions in the new upcoming government's coalition agreement becomes reality. Here, it is proposed to increase the renewable share of electricity production further from 50 to 65 per cent in 2030,<sup>3</sup> which will significantly increase the pressure on the grid, in particular as the main sources of renewable energy expansion is expected to be intermittent wind and solar sources. This trend will continue through 2030 and towards 2050, and in addition to the developments in Germany, it is expected that Germany's surrounding countries will decarbonise.

The NEP has successfully enabled the first phase of the *Energiewende*. The measures that are today listed in the German Federal Requirements Plan Act (*Bundesbedarfsplangesetz*, BBPlG) and the Power Grid Expansion Act (*Energieleitungsausbaugesetz*, EnLAG) are the absolute Minimum of investments necessary for the transmission grid to be able to take on large amounts of renewable energies. The measures listed in the BBPlG and the EnLAG are therefore no-regret measures and must be the starting point for all further investments in the future grid planning 2.0. However, it is increasingly being questioned whether the current NEP process is fit for the massive transformation of the energy system that lies ahead.<sup>4</sup> A key issue is the robustness of the identification and evaluation of grid investments. An example: the existing NEP scenarios already include some impact from

<sup>3</sup> See the coalition agreement between CDU, CSU and SPD. Can for example be downloaded on the CDU's website under <https://www.cdu.de/koalitionsvertrag-2018> (German only)

<sup>4</sup> Studies by Agora Energiewende (2018) "Toolbox für die Stromnetze" and Agora Energiewende (2017) "Optimierung der Stromnetze" for example point out weaknesses in the current grid planning approach

alternatives to grid investments such as demand side management, sector coupling and storage technologies, reducing estimated capacity needs in 2030. But how fast will the economic viability and scalability of such alternatives grow in the coming years? How many new investments are necessary? Grid investments have a significant impact on society and politics and this should be seen in the context that grid assets have an expected lifetime of many decades. The overall question is therefore:

*Is the current NEP process designed in a way so it ensures – also after 2030 – that grid expansion is done to an optimal extent, is cost-efficient and socially accepted although we do not know with certainty how technologies and market conditions will develop by then?*

This is the question raised by TenneT in late 2017 and this is the question we evaluate and answer in this study. The short answer is *No*. The NEP has markedly improved grid investments regarding their transparency and reliability, but ultimately, we conclude that NEP is not fit for meeting the challenges ahead in the continued transformation of the German energy system.

Based on our analysis, we propose a *reform package* to the German grid planning process based on three key principles to be introduced progressively in future NEPs:

- *Robust evaluation of grid investments in a longer term perspective.* This includes the introduction of a net-value approach covering cost and benefits over a long period instead of the current planning concept of a bottleneck-free grid based on a single year estimation (currently 2030). In addition, the NEP should provide a structured framework for the evaluation of short-term ad-hoc-measures.
- *Explicit treatment of the large investment risk and opportunities.* The need for grid investments depends on large number of factors with a lot of real uncertainty relating to societal developments and the speed with which alternative solutions to grid investment emerge. The evaluation of grid investments should to a larger extent reflect this uncertainty with more in-depth treatment of the most important factors e.g. economic maturity of alternative solutions, location of renewable power etc.
- *More flexible approach to grid planning.* The current NEP process is very resource consuming and leads to very detailed and rigid commitments to individual investment projects. We suggest to increase the frequency of submitting the NEP from two to four years and/or when major changes in investment drivers are identified. For the years in between, we recommend lighter yearly or bi-annual reviews (monitoring reviews) to assess major changes in assumptions behind investment needs. Based on those reviews, the TSOs should be allowed to move projects up or down the (not yet existing) priority list. By clarifying the long term grid investment costs associated with a number of different scenarios, such reviews can also contribute valuable input to the wider energy policy discussion. It could e.g. identify policy measures that could help drive down the costs of the energy transformation e.g. targeted support to new technologies and changes in power market design etc. to alleviate the need for increased grid investments.

## CHAPTER 1

# REFORM PRINCIPLE 1: MORE ROBUST EVALUATION OF GRID INVESTMENTS IN A LONGER TERM PERSPECTIVE

The most important outcome of the NEP process is a list of projects that the TSOs jointly submit to the regulator for approval. In order to arrive at this project list, the TSOs have evaluated the value to society of the projects recommended. While this process is quite advanced, analytically complicated, and resource intensive for the TSOs, it is actually based on a very simple concept for determining the need for specific projects; namely the concept of building the *bottleneck-free grid* in a given year. For the most recent NEP that year is 2030.

In this chapter, we argue that this simple concept is in fact too simple to capture properly the value to society from different grid investments. We recommend an improved approach to project evaluation and prioritisation, including more focus on both the short run and the long run. We first identify three areas where a more robust evaluation approach could add value (sections 1.1 to 1.3), then we suggest some guidelines for putting our recommended approach into practical use in the NEP (section 1.4).

## 1.1 THE BOTTLENECK-FREE GRID IS TOO SIMPLE FOR ASSESSING SOCIETY'S NEED FOR NEW GRID

The most important concept in the NEP is the planning criteria that the grid should be free of bottlenecks. This stipulates that in a specific year, a line should be built if there otherwise would be a bottleneck in the existing grid. This approach has the drawback that even temporary and very short-lived bottlenecks in the grid can motivate grid investments, even if the costs of alleviating such a temporary bottleneck would be higher than the benefit.<sup>5</sup>

By applying this planning principle in the NEP, the recommended projects from the NEP constitutes a mix of projects that solve a high amount of bottlenecks, and projects that solve very few bottlenecks. In the current NEP project list for example, the 10 per cent most effective projects in terms of bottleneck alleviation solve bottlenecks in more than 3,900 of the 8,760 hours per year on average, so in 45 per cent of all hours. The 10 per cent least effective projects on the other hand only alleviate bottlenecks in 170 hours per year on average, which means in 2 per cent of all hours. Nonetheless, all projects are treated equally, and all are recommended for approval, even though they some are clearly more, some less beneficial for society.<sup>6</sup> With the potential jump to 65 per cent renewable energies and the goal of a de facto 100 per cent renewable energies by 2050, it is likely that all measures currently listed in the Power Grid Expansion Act (EnLAG) and the Federal Requirements Plan Act (BBPlG) will be needed. Considering the uncertainties regarding the future technological development, this way of thinking cannot continue going forward (e.g. with regards to the measures after 2030).

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<sup>5</sup> The concept of the bottleneck-free grid means that a project must be suggested for each bottleneck in the grid. That does not mean that all those suggested projects are actually implemented, since the regulator (BNetzA) does not approve all projects. The grid is therefore in reality never fully bottleneck-free, and redispatch and curtailment are commonly made use of.

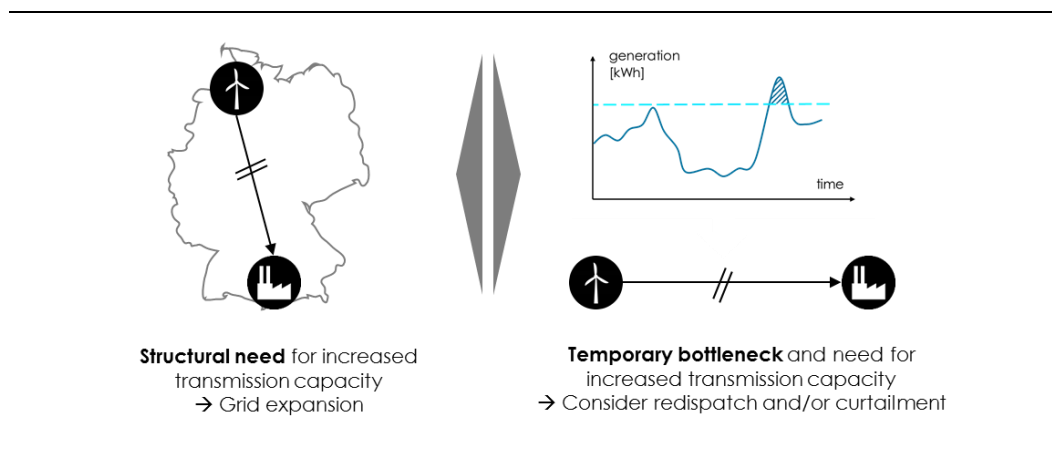
<sup>6</sup> Some of the projects in the last NEP have been declared “not worth suggesting” (*nicht vorschlagswürdig*) by the TSOs, which means that there is some differentiation between projects. However, this differentiation is no sufficient prioritization, and neither sufficiently structured, well-established or transparent.

**Recommendation 1.a**

Use transparent cost-benefit principles as the main prioritisation criterion for determining the need for new grid projects instead of the 'bottleneck-free grid'

The value of building more grid is linked to the service it provides to the electricity system. This service is typically defined as being able to transport electricity from where it is generated to where it is consumed at all points in time. However, as the transmission requirements are different across geographical areas and over time, the value from additional grid capacity will vary significantly. For example, some lines will serve to alleviate structural overcapacity in the capacity-expanding North by transporting it to the demand-intensive South. Conversely, other lines will primarily serve a security of supply purpose by alleviating temporary bottlenecks from fluctuating generation, see Figure 2.

**Figure 2**  
**Structural need vs. temporary bottleneck**



Source: Copenhagen Economics illustration

If there is a structural need for increased transmission capacity, then grid investments are typically reasonable and worth pursuing.<sup>7</sup> In the case of temporary bottlenecks, it can often be beneficial not to expand the grid to meet the full peak. Redispatch and curtailment should instead be considered as alternative solutions.

Consequently, it is important not just to look at whether a grid investment alleviates a bottleneck, but whether this bottleneck could more cost efficiently be alleviated by e.g. redispatch.

In the market simulations in the current NEP, the maximum generation level of renewable energy is reduced by 3 per cent in peak hours. While this to some extent take into account the principle of not dimensioning the grid to the last MW of volatile generation, we argue that the 3 per cent-rule is too general. The optimal curtailment rate will vary from location to location and will depend on the particular peaks of different renewable energy sources. Consequently, we recommend a more flexible approach where the optimal curtailment is defined project by project. In other words, curtailment

<sup>7</sup> Such an assessment and cost-benefit-analyses in general should ideally not only consider Germany, but also the rest of Europe.

should be an actual tool that can be used in market operation and balancing when needed, instead of an overall, fixed assumption.

**Recommendation 1.b**

If it is best for society to alleviate a bottleneck through redispatch and curtailment, do so – and do not build additional grid projects.

## **1.2 THE NEP DOES NOT EVALUATE BENEFITS IN THE FULL LIFETIME OF A GRID INVESTMENT**

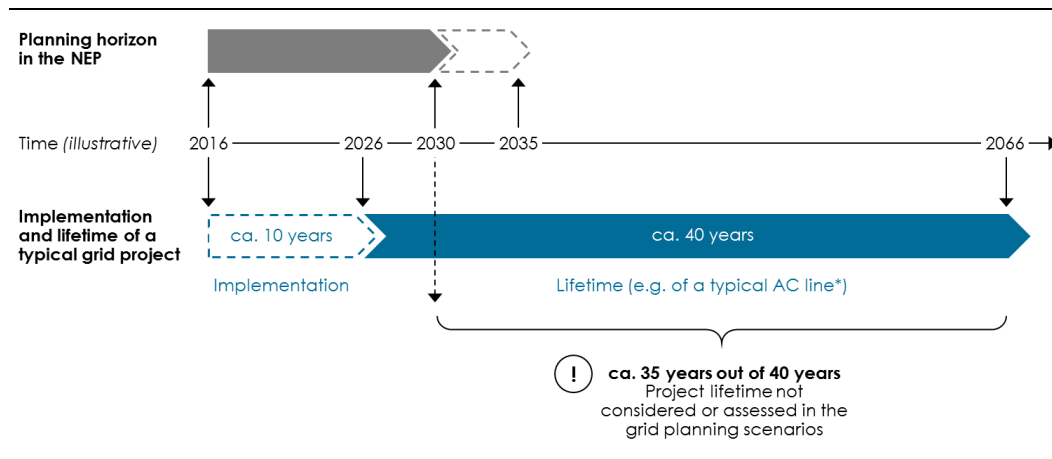
The NEP in its current form focuses on a particular year 10-15 years in the future<sup>8</sup> – for the last NEP, that year is 2030. The assessment estimates the risk of bottlenecks in that particular year and identifies which projects should be implemented to alleviate the bottlenecks. Potential bottlenecks before or after this particular year will not form part of the assessment.

The consequence is that the NEP does not assess any potential benefits in most of the lifetime of a grid investment. For example, a project decided in 2016 will need ten years until 2026 before it is operational but the benefit of the project in the current NEP will be evaluated in 2030 after only 4-5 years of operation. The benefits accruing in the remaining 35 years of lifetime are simply ignored, see Figure 3. Here, too, can be stated that the assumption that the grid projects listed in the law will be no-regret-projects in the digital and green energy world of the future. However, this does not necessarily hold for all future projects which would – following the current NEP logic – be necessary in the years after 2030.

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<sup>8</sup> Following EnWG §12a, "Szenariorahmen für die Netzentwicklungsplanung"

**Figure 3**  
**Planning horizon in the NEP vs. lifetime of grid projects**



Source: Copenhagen Economics illustration

### Recommendation 1.c

Use a net-present value approach that takes costs and benefits over the full lifetime into account.

## 1.3 THE NEP DOES NOT GIVE ROOM TO CONSIDER SHORT TERM SOLUTIONS

The NEP focuses on the medium term 10 to 15 years from now, and recommends traditional grid investments<sup>9</sup> that can address challenges in that time perspective. However, these investments can easily take 10 years to implement and become operational.

This means that the NEP does not assess whether there will be a gap between the need for grid and the supply of grid during construction in the period up to 2030, even though current expectations are that there will be less grid than actually needed. That means that with the current implementation speed of already approved projects, there will be an increasing need to perform costly market operations, such as redispatch and curtailment of wind energy. Following current expectations, it is also doubtful whether the so-called 'target grid' envisaged to be in place in 2030 can in fact be operational given the long implementation periods.

However, the toolbox of the TSOs also include so-called *ad hoc measures*, which typically help optimising the existing grid, and which can be implemented much quicker than traditional grid solutions. High temperature overhead lines can for example transport up to double the amount of electricity than ordinary overhead lines,<sup>10</sup> and phase-shifting transformers are considered very effective short- and medium-term solutions to bottlenecks.<sup>11</sup>

<sup>9</sup> Grid reinforcement and expansion, such as laying copper and building transformer stations

<sup>10</sup> BMWi (2015) Stellungnahme zum BNetzA-Konzept für ein zukünftiges Verfahren für Netzausbaupläne (NAP) auf der 110-kV-Ebene, referring to dena (2012), Erneuerbare Energien (2011) and RWTH Aachen

<sup>11</sup> Agora Energiewende (2018) Toolbox für die Stromnetze

In order to get approval for a grid investment, including an ad-hoc measure, it is required that the investment appears on the NEP project list. While some single ad-hoc-measures have been suggested in the last NEP 2030 (version 2017) and have later also been implemented. But since there is not an explicit treatment of the short run in the NEP, it is difficult to show the value of these ad-hoc measures. Consequently, we suggest that a process is established for deciding on investments in ad-hoc measures.<sup>12</sup>

#### **Recommendation 1.d**

The NEP process should be capable of considering ad hoc measures as solutions.

## **1.4 GUIDELINES FOR PRACTICAL IMPLEMENTATION**

Based on Based on the recommendations above, we propose the following guidelines for practical implementation: NEP should make use of a *net present value approach* in order to 1) consider the full lifetime of a project, and 2) to take explicitly into account both costs and benefits of projects. We have three practical suggestions:

1. Create a framework for assessing ad-hoc measures in the short run
2. Conduct a pragmatic cost-benefit assessment for small and medium-sized projects
3. Conduct a thorough cost-benefit assessment for the largest grid investments (e.g. HVDC cables)

### **1.4.1 Create a framework for assessing ad-hoc measures in the short run**

A framework for deciding on short-run investments should be established. This would include a short-term reliability assessment (for the next 5-10 years), highlighting potential implementation gaps by taking into account the expected bottlenecks in the grid and the capacity of already approved projects to alleviate these bottlenecks.

Based on this assessment, the TSO should develop a business case based on cost benefit principles and decide whether ad hoc measures would be a better option than the alternative, market operations (mainly redispatch, but also curtailment of wind power).

In the comparison between ad hoc measures and market operations, it should be defined which parts of the market operations that give rise to actual socioeconomic costs, and which parts that are just transfers from the public to owners of power plants and renewable energy. This includes also an assessment of the socioeconomic value of avoiding curtailment of subsidised renewable energy, see Box 1.

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<sup>12</sup> This process also be established outside of the NEP, if that makes most sense.

### **Box 1 Short- and long term cost benefit calculation of curtailment of renewable energy version grid expansion**

This assessment needs to be clear on the underlying assumptions with regard to the time horizon and the treatment of sunk costs.

The marginal costs of producing power from already installed wind power capacity is very low. Indeed, wind power is characterised as having very high investment costs per unit of energy produced and very low marginal running costs. So the simple benefit calculation would compare the increase in value to society by allowing marginal wind based power to flow to a higher price region and bringing down consumer costs in that region. On the cost side, would be an increase in grid capacity costs. The net calculation would inter alia be depending on the level of utilisation of the marginal grid capacity and differences in marginal power market production costs on either "side" of a bottleneck.

In a long term perspective, the level of installed capacity is a not given but the result of policy choices and developments in technology. This implies that the benefits of an increase in grid capacity to avoid the need of curtailment looks very different. A proper integrated cost-benefit analysis would review if an expansion in the capacity of e.g. wind power in a given region would have a value to final consumers large enough to pay for the investment costs of the wind power installation as well as the increase in grid capacity costs.

Note: In this box, we elaborate which types of economic considerations should be made when discussing grid expansion in the long and short run in combination with renewable energies. This does not mean that the analyses mentioned here must or should be conducted by the TSOs.

Source: Copenhagen Economics

#### **1.4.2 Conduct a pragmatic cost-benefit assessment for small and medium-sized projects**

In order to introduce a project evaluation based on socioeconomic principles, without excessive amounts of administrative work and costs, we propose a pragmatic cost benefit assessment for small and medium sized investment projects based on simple net-present-value calculation and the use of rules of thumb.

One of the main benefits of improving the grid is the efficiency gain of ensuring that power is generated where it is cheapest and transported to the consumers who are most willing to pay. Without sufficient grid capacity, low-cost generation will have to be regulated down and high-cost generation closer to consumers will have to be regulated up. The value of this benefit can be captured by assessing the redispatching and curtailment/market operations that would otherwise had been needed to alleviate a particular bottleneck. This benefit is quantifiable and already to some extent quantified in the NEP process.<sup>13</sup> Consequently, we suggest conducting a simplified CBA, comparing the saved redispatch costs over time with the investment costs of the project. This should be done while keeping in mind that this is only *one* of benefits of the project.

As a rule of thumb, we suggest to calculate a standardised metric for the value of alleviating a bottleneck through saved redispatch costs. While this value in practice will be different in different parts of the grid, an average number could be calculated through simple averages over bottlenecks or

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<sup>13</sup> The quantifications are not published, but supports the published assessment of benefits

through more advanced econometrics.<sup>14</sup> Such a simplification will make the assessment significantly easier, also when assessing risk and robustness. It should be tested, whether this simplification will be too simple to use in actual project valuation.

In the current NEP, the cost of grid projects is already roughly estimated through a rule of thumb. This rule specifies that the costs depend linearly on the length of the line or cable, and applies a standardised 'cost per kilometre'-factor. This existing practice could easily be integrated in the suggested simplified CBA.

The approach to a simplified CBA is illustrated in the following box using project P113 as an example.

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<sup>14</sup> E.g. using an econometric approach

### Box 2 Practical example: a simplified CBA step by step – exemplified by P113

Project P113 is a grid reinforcement project in Northern Germany. To arrive at a simplified NPV, we suggest the following steps:

1. **Calculate the number of bottlenecks alleviated through the project in 2030.** P113 for example alleviates 3,234 bottlenecks in the target grid (a different grid or the average grid can be used if more meaningful). This number of bottlenecks is then assumed to be constant over the lifetime of the project (approx. 40 years), or over a shorter period of 20-25 years<sup>15</sup> as stipulated by ENTSO-E.<sup>16</sup>
2. **Calculate the saved redispatch costs per saved bottleneck for the project, or use the standardised metric** (average value of one alleviated bottleneck). The first approach, a project specific calculation, is more precise, but also more time consuming to conduct. It can for that reason make sense to calculate a standardised metric reflecting the average value of one alleviated bottleneck, and to apply that to all or most projects and bottlenecks.
3. **Estimate the implementation costs** by multiplying the length in kilometres with the standard costs per kilometre. Different standard costs apply for different categories (as already today – no changes needed here), e.g. km of reinforcement vs. km of new construction. For P113, standard costs for line works over 136 km plus an ad-hoc measure suggest costs of approx. EUR 265 million.
4. **Discount costs and benefits to their present value;** if the implementation costs can be assumed to incur in the first year, only the benefits from saved redispatch have to be discounted. The standardised metric already takes into account discounted future benefits.
5. **Compare present costs and benefits.** Project P113 is estimated to have implementation costs of EUR 265 million. The benefits of the project depend on the value ascribed to the alleviation of bottlenecks through project P113. Should the value of the 3,234 bottlenecks that P113 alleviates be lower than EUR 265 million, then the (simplified) net present value will be negative. If the value is above EUR 265 million, then the (simplified) net present value will be positive.

Note: Illustrative example

Source: Copenhagen Economics

### 1.4.3 Conduct a thorough cost-benefit assessment for the largest grid investments

Grid investments typically have a long lifetime. As a rule, the largest grid investments will have the largest risk of being underused particularly during the end of their lifetime. Such investments are called stranded assets: once built they have no alternative uses in other parts of the economy. Hence, stranded assets can potentially be a large cost to society. On the other hand, several smaller investments can seem profitable individually, but as a package, they might have a lower social and/or economic value than a large investment.

Grid optimisation and reinforcement are typically less costly than building new lines and cables, and less controversial in terms of public acceptance. However, there can be exemptions. Construct-

<sup>15</sup> In chapter 2, we illustrate how this shorter lifetime can be extended to include risk/robustness

<sup>16</sup> ENTSO-E (2015) Guidelines for Cost Benefit Analysis of Grid Development Projects

ing new lines can have lower overall costs (e.g. economic, social, environmental costs) than reinforcing existing lines, and in such cases, the socio-economically most valuable solution should be pursued.

The potential socio-economic costs of misjudgements of that kind will be largest for the biggest and most expensive grid investments. For such investments, it is therefore of utmost importance that the investment decision is based on a thorough assessment.

We therefore propose to undertake a complete assessment based on standard cost-benefit principles for the largest investments. This could e.g. be done for the HVDC corridors. The cost-benefit assessment does not necessarily have to be part of a standardised NEP process, but it should follow the same scenarios and methods applied in the NEP.

We suggest the following principles for the thorough cost-benefit assessment:

- *Consider all benefits and costs, also the ones difficult to quantify.* This includes e.g. also the value to system security and the potential impact on reserve dimensioning (n-1 criteria). The ambition should be to apply the same analytical treatment as applied in e.g. assessments under the TYNDP or under Commission assessments of projects of common interest (PCI)
- *Consider a sufficiently long period.* One approach to value benefits over time is to use the norm adopted by e.g. the European Commission, which is to assess the benefits in a period of 20-25 years only,<sup>17</sup> even though the average lifetime of grid assets typically is around 40 years. We would argue, however, that this approach is very conservative, as it does not allow any value to be reaped in half of the assets' lifetime. Instead, one could consider using a higher discount rate for the longer term reflecting the increased uncertainty.
- *Use the standard CBA principles and assumptions applied by e.g. ENTSO-E and the European Commission for the assessment of Projects of Common Interest (PCI).*

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<sup>17</sup> ENTSO-E (2015) Guidelines for Cost Benefit Analysis of Grid Development Projects

## CHAPTER 2

# REFORM PRINCIPLE 2: EXPLICIT TREATMENT OF INVESTMENT RISK AND OPPORTUNITIES IN THE LONGER RUN

Within the next 20-30 years, the European electricity system will look very different than it does today. Massive integration of volatile renewable energy combined with digitalisation and new technologies for automating and optimising the grid will transform the system, as we know it. New technologies and processes entail large opportunities for improving the electricity grid functioning but at the same time it entails large risks for long-term investment decisions taken today (“stranded assets”). Germany needs a NEP approach that can help making better investment decisions by reflecting this technological uncertainty and its implications.

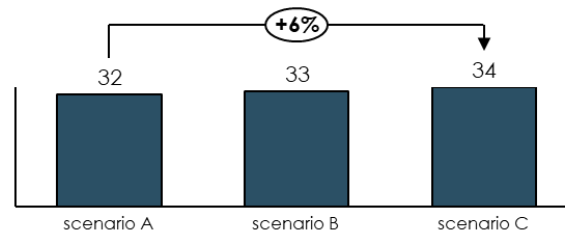
In this chapter, we argue that the current NEP process does not treat sufficiently the large uncertainty of the future, and that it does not consider this uncertainty appropriately in decision-making. Concretely, we argue that the NEP does not capture the relevant risks in the mid-term, and that it does not look sufficiently far in the long-term (section 2.1). Instead, we propose to implement pragmatic principles for dealing more explicitly with long-term risk (section 2.2).

## 2.1 THE NEP DOES NOT CAPTURE LIKELY LONG-TERM DEVELOPMENTS

The NEP operates with three different future scenarios for the respective target year (in the last NEP, 2030) that are supposed to capture potential uncertainty in the development of key variables, including available technologies.

However, these scenarios seem to consider unrealistically little variation in the potential outcome. One reason for that is that the legal basis for the NEP, the EnWG, requires the scenarios to reflect “likely developments” against the background of the government’s political objectives. In fact, the difference in estimated grid costs between the high and the low scenarios for 2030 is only 6 per cent (or EUR 2 billion), going from EUR 32 to 34 billion, suggesting that the underlying uncertainty and risk that is taken into consideration is very limited, see Figure 4.

**Figure 4**  
**Total grid investments in the three scenarios of the NEP 2030 (version 2017)**  
Billion EUR



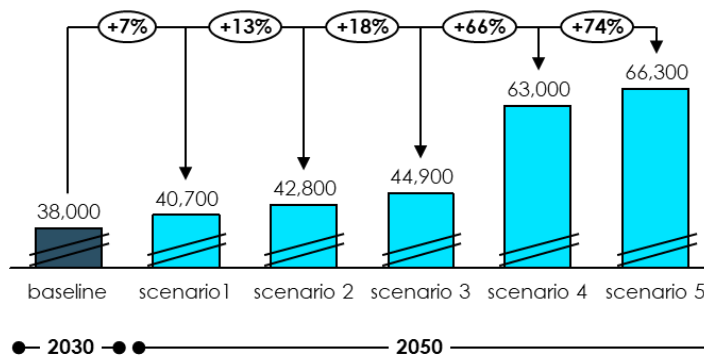
Source: 50hertz, Amprion, TenneT and TransnetBW (2017) NEP 2030, 2017 version

This is in contrast to other scenario analyses that show considerable variation in their key variables, even in 2030. The e-Highway project for example works with 4 scenarios for 2030 which vary in their installed capacity of RES in Germany in 2030 by almost 50 per cent.<sup>18</sup> The variance is less extreme, but still significant around 20 per cent for the three 2030-scenarios considered ENTSO-E's ten year network development plan (TYNDP).

As the NEP does not consider the time after 2030, it does not evaluate the real long-term implications of the grid projects. However, the expected state of the electricity system and the grid in 2050 must also affect investment decisions made already today, as the lifetime of these investments are around 40 years. Consequently, it becomes important to understand the long-term drivers and risks, which can have very different implications for the recommended grid investments. European scenario analyses for 2050 suggest that the required grid investments from 2030 would need to increase in a very wide range of 7 to 74 per cent depending on the underlying drivers, see

<sup>18</sup> relative to the lower value. The lowest scenario, "constrained progress", assumes installed RES capacity of 128,000 MW, while the highest scenario, "National Green Transition" assumes 188,000 MW.

**Figure 5**  
**Additional grid investments for Germany in five different 2050 scenarios of the e-Highway project as compared to 2030**  
GW-km



Note: includes cross-border lines and cables

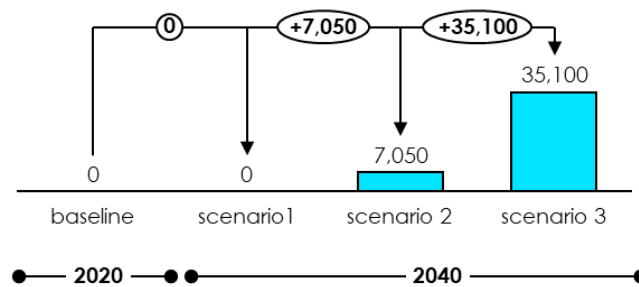
Source: European Commission (2015) e-Highway 2050. Modular Development Plan of the Pan-European Transmission System 2050, data set

Consequently, this lack of a long-term risk perspective can lead to two types of potentially large investment risks to society. *First*, there is a risk of approving investments that should *not* have been approved. These are investments that *may not be beneficial* for society in the long-term if new or better technologies are expected to materialise in the future, but they *may erroneously appear beneficial* if they are evaluated only in the short-term.<sup>19</sup> *Second*, there is a risk of *not* approving investments that should have been approved. These are investments that *may be beneficial* for society in the long term if they mostly deliver value in the future, but they may erroneously *not appear beneficial* if they are evaluated only in the short-term. It may also be that investments may be beneficial in the long term but lack social acceptance due to the large number of projects in the approval process.

The risk of *'building too much'* is important as the investments required to reinforce or build new grid are sizeable. In the most recent NEP, the average investment costs were estimated to amount to EUR 33 billion until 2030. In addition, building grid where it is not necessary will have a negative impact on socio-political factors like acceptance and trust into the TSOs' calculations. Going forward, new technologies and solutions may reduce the socioeconomic value of the investments by reducing the need for transporting electricity as expected today. As an example, the expected commercialisation of electricity storage can influence the need for new grid, but is at the same time associated with significant uncertainty. Estimates from the common European TYNDP scenarios illustrate the large uncertainty. They operate with scenarios of both zero (0) GW storage capacity and of 35 GW storage capacity in Germany in 2040, see Figure 6. As a comparison, NEP assumes that there will be between 3 and 6 GW storage capacity in 2030.

<sup>19</sup> This risk is to some extent avoided by both the EU practice of only considering a 20-25 year period for investment projects thereby de facto giving zero benefit to the period beyond, and by the German principle of 'unzulässige Vorratsplanung'.

**Figure 6**  
**Storage in Germany in the three different 2040 scenarios as compared to 2020 in the TYNDP**  
MW



Source: ENTSO-E (2017) Completing the map. The Ten-Year Network Development Plan. 2018 System Needs Analysis, background data

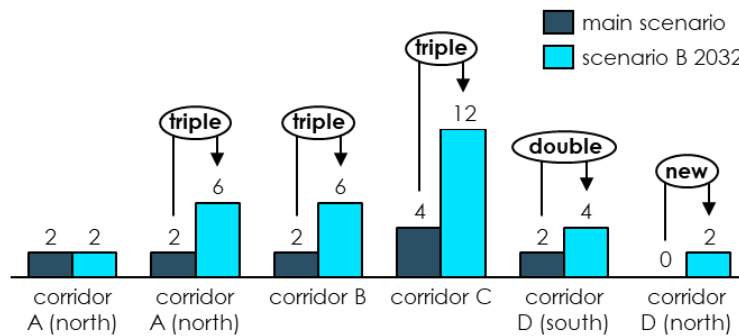
The risk of *'building to much'* is particularly high if two conditions hold. *First*, if the net-value calculation relies heavily on benefits many decades into the future where other technologies may be less costly or societal conditions driving investment needs have vanished or never materialised. *Second*, if alternative technologies solving the particular problem have a high probability of being economic viable in a not too distant future. For the moment, this appears increasingly as a realistic alternative to shorter term balancing problems and less so for dealing with longer periods of underproduction in larger areas<sup>20</sup>.

This risk of *'not building enough'* can also turn out to be too costly for society. *First*, it might lead to too much inefficient redispatch and curtailment and hinder the integration of renewable energy. *Second*, instead of building larger HVDC corridors in the first place, it could lead to too many smaller investments e.g. in AC lines in the short run that would then turn out to be uneconomical once the needed HVDC corridors were established in the future. *Third*, it can often be more expensive to expand a line when it has been dimensioned to a smaller size rather than explicitly designing it with the option of increasing the size at a later stage.

As an example, consider increasing the share of renewables in the system. In 2012, the German TSOs estimated that most of the planned HVDC corridors should either double or triple in capacity, if the renewable energy share increased from 59 to 67 per cent in 2032, see Figure 7. In absolute numbers, the planned transmission capacity should increase from 12 GW to 32 GW. This illustrates that the need for grid investments depends strongly on the amount of volatile renewable energy, and that taking different risk scenarios into account when planning new investments is purposeful.

<sup>20</sup> See for example Energinet(2017), "Energinets analyseforudsætninger". Heat pumps is a relatively mature technology to deliver flexibility over shorter periods of time but does not solve a problem of low production from wind power over longer periods or structural import needs in a region.

**Figure 7**  
**Needed capacity for the German HVDC corridors**  
GW



Source: 50hertz, Amprion, TenneT and TransnetBW (2012) NEP 2022

The risk of not building enough is particularly important if three conditions hold. *First*, if there are significant benefits of scale and scope of planning and building for the large solution now or in the near future. *Second*, if the probability of needing the large solution is relatively high. *Third*, some of projected costs are avoidable or recoverable if not needed. There might for example be large benefits from planning for the larger corridor while the actual physical investment can be delayed until the need is more clearly identified.

Our point here is not that the future can be predicted; on the contrary. The developments in technology, policy and social preferences cannot be predicted but will nonetheless have a major impact on whether investment decisions in the grid will turn out to be good or not. Therefore, we recommend that the NEP adopts a more risk-based approach to project evaluation, including:

### Recommendation 2.a

Conduct illustrative long-term scenarios, highlighting risks and opportunities and their implication for investment needs.

The risks **over** versus **under** investments should be based upon three relative risk metrics:

- **Late/early** concentration of net-value benefits in the life time of grid
- **High/low** probability of economically viable technologies appearing as alternatives early in the life time of grid investment
- **Limited/substantial** potential for some recuperation/avoidance of cost if need for investment disappears between adoption in the NEP and actual construction

## 2.2 GUIDELINES FOR PRACTICAL IMPLEMENTATION

Based on the recommendations above, we propose the following guidelines for practical implementation, adding a more *risk-based investment approach* to the NEP. We propose three practical variations:

1. Prepare road maps for reaching the long-term policy objectives of the *Energiewende*<sup>21</sup>
2. Conduct a robustness check of the NPV calculations based on a set of risk indicators
3. For large investments, conduct a fuller sensitivity analysis

### **2.2.1 Prepare road maps for reaching the long-term policy objectives of the *Energiewende***

It is clear, that in order to achieve the *Energiewende* and the objective of a minimum of 80 per cent renewable energy in electricity generation in 2050 (or earlier), a large transformation of the generation assets need to take place. In the absence of technological progress, this transformation will also massively increase the need for additional grid investments today and going forward. In order to assess and understand the risks of current grid investments, it is important to depict potential long-term paths consistent with the policy objectives. Such a picture could also be used to assess the benefits of technological innovation e.g. specific research and development programmes as well as innovation and deployment projects. In this regard, better incentives for the TSOs and DSOs are needed to promote the development and implementation of new solutions that can be a cost-efficient substitute for tradition grid expansion.<sup>22</sup>

In concrete terms, we propose to conduct at least two long-term scenarios consistent with the policy objectives in the *Energiewende*. Digitalisation and technological progress makes it increasingly uncertain to predict the long-term requirements of the grid, as e.g. demand side management and commercialisation of large-scale storage can dampen the need for new grid investments. This also holds for the optimisation and automation of system operations, which is however as of today not yet ready for large-scale use. Nonetheless, it is important to illustrate different paths to a policy-consistent 2050, e.g. a low technological progress scenario and a high technological progress scenario.

### **2.2.2 Conduct a robustness check of the NPV calculations based on a set of risk indicators**

We suggest that the NPV calculations for each project, as suggested in chapter 2, are supplemented by a robustness check based on a set of risk-indicators. The risk indicators should be based upon the metrics in recommendation 2.a. These indicators should support an understanding of the risks associated with a given project, including the nature and drivers of these risks. A project reinforcing a transmission line to consumers that are likely to be more flexible in the future faces different risks

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<sup>21</sup> The regulator (the BNetzA) should play a crucial role in the preparation of this road map.

<sup>22</sup> To facilitate the growth of new solutions to deliver more flexibility in the grid system, the incentive structures for both transmission and distribution operators – TSOs and DSOs – need to change as well. Indeed, we are seeing in particular DSO regulation being changed in a number of countries as a response to the marked increase in distributed generation such as solar and (often) wind power. Tariff structures are being shifted with more weight on capacity put in place as opposed to current delivered to customer. The basic point here is that customers more and more act as producers, too, who increasingly use centrally produced power as a backup to own production and the grid as means to balance own production and consumption needs (see European Commission (2017) Study on Residential Prosumers in the European Energy Union, or CEER (2015) The Future Role of DSOs). Furthermore, with larger fluctuation in the production of power relative to production, the value of customers and third parties providing more flexibility services to the TSOs and DSOs is increasing. However, in Germany as in other countries this latter option is often unattractive from a TSO or DSO perspective because regulation tends to favour solutions that increase the regulatory physical asset base such as grid investments (see Smart Grid Task Force (2015) Regulatory Recommendations for the Deployment of Flexibility, or CEER (2015) The Future Role of DSOs). By contrast, buying flexibility services is just seen as an additional expense offering no services to customers even when it alleviate the need for grid investments. For that reason, we recommend a more technology neutral incentive structure also in Germany for TSOs and DSOs.

than a project facilitating a structural flow of electricity from new generation locations to consumers.

In order to provide a view of such risks, we suggest assessing each project based on a number of risk-indicators. Examples of risk indicators could be the following:

*Indicator 1: Short/medium-run risk.* What is the expected viability of a project in the short- or medium run? The NEP should construct a few scenarios with more variation in the assumptions, and the NPV calculations should be done based on resulting hours of bottlenecks. The indicator can be constructed as the share of scenarios where the project has a positive NPV and/or as the average (expected) NPV value across scenarios.<sup>23</sup>

*Indicator 2: Long-run risk.* Are some projects more or less susceptible to long-run risks? The NPV calculations of each project should be tested against the long-run scenarios. The relevance of some projects might be more susceptible to e.g. the development of demand side management solutions than others, and such risks would be important to highlight. One practical way of approaching this is to work with Technology Road maps which on an on-going basis follows improvements in key technologies that may prove helpful in dealing with different types of imbalances in the grid ie. local, short term imbalances within an hour or day versus imbalances linked to long periods of production surplus/deficits within a region. Roadmaps outline the maturity and scalability of these technologies over time and keeps track also of policies put in place to foster the growth of new solutions. This can in turn be used in the grid planning when combined with the other drivers of grid investments.<sup>24</sup>

We are not suggesting constructing a full new project list in 2050, but assessing the relevance of the medium-term project list under different assumptions for 2050. Practically, this could be done by including the estimated number of bottlenecks in the NPV calculation for 2050, and making a linear interpolation between 2030 and 2050.

*Indicator 3: Project specific risks.* There will be different underlying reasons for why a particular project is identified as relevant. Some projects might solve a structural need for an internal transport corridor, while other projects will solve a local need e.g. linked to the specific location of a new data centre. In order to understand the investment risk for society, these underlying drivers should be identified and specified.

One way of assessing these risks would be to run different sensitivities on the established scenarios and investigate how sensitive is the number of alleviated bottlenecks of a concrete project to e.g.:

- whether the increase in renewable energy towards 2030 is primarily wind or solar
- where new generation is located geographically
- the extent and location of data centres
- The establishment of a new (or larger) HVDC corridor

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<sup>23</sup> Other concepts for 'decision making under risk' could also be applied such as the maximin approach or the minimax regret

<sup>24</sup> For a short overview, see e.g. IEA(2014), "Technology Roadmap", Energy Storage. The Danish TSO makes some use of such roadmaps in its grid planning se e.g. Energinet(2017), "Energinets analyseforudsætninger" and has published recently updated its own technology assessment in Energinet (2017), "Technology Data for Energy Plants"

Based on these indicators, the TSOs can assess both the expected NPV (net present value) of a project in the 'base scenario' and to what extent the NPV is robust in different risk scenarios. We have made a simple illustration of how to expand the NPV calculation to conduct such a robustness check, see Box 3.

### Box 3 The robustness check exemplified at P113

From the CBA in chapter 1, we know that project P113 alleviates 3,234 bottlenecks, which has a (simplified) value of EUR 259 million, while the implementation costs are – estimated based on standard costs – roughly EUR 265 million. That results in a NPV of EUR -6 million. This NPV however reflects the baseline, the scenario B in the NEP. The robustness check reveals to which extent the NPV will change under different assumptions.

To make a simple assessment of the risk in the **short to medium run**, we suggest to re-calculate the NPV based on different numbers of bottlenecks – as a minimum for the bottleneck-numbers that follow the other two NEP scenarios, C and A. This is very simple and straight forward calculation, as it only relies on changing one number in an equation – the number of bottlenecks – which then remains constant over the years (as it al-so does in the baseline), see table below.

Scenario	Number of bottlenecks				NPV [mio EUR]
	2030	2031	2032	...	
Baseline (scenario B)	3,234	3,234	3,234	...	- 6
Scenario C	3,557	3,557	3,557	...	+ 20
Scenario A	2,991	2,991	2,991	...	- 15
New scenario	4,000	4,000	4,000	...	+ 65

If feasible, the short- and medium-run risk assessment can of course contain more sensitivities, for example different assumptions for key variables (e.g. storage, technology, the RES mix), or varying implementation costs. If the standardised metric for the value per alleviated bottleneck means a (too) large simplification of reality, further sensitivities can cover other or more elaborate values per bottleneck.

To make a simple assessment of the risk in the **long-run**, we suggest to make simple scenarios for 2050 and model how many bottlenecks the project then will alleviate. From that bottleneck-number in 2050, linear projections are made backwards towards the 2030 baseline, see table below.

Scenario	Number of bottlenecks			
	2030	...	...	2050
LR scenario I	3,234	...	...	4,000
LR scenario II	3,234	Linear projections		5,000
LR scenario III	3,234	...	...	8,000


We suggest making at least 2-3 long-run scenarios. The long-run risk assessment should also hold: more (meaningful) scenarios can of course be made if feasible. Such scenarios could for example start at different 2030-bottleneck-values (e.g. those of scenario C and A).

Note: Illustrative numbers.

Source: Copenhagen Economics

Based on these NPV calculations, the NEP can produce a robustness assessment based on the three main indicators (short- to medium term risk, long term risk, project specific risk) as outlined above. We suggest to make clear and well-structured overview of those indicators. Table 1 can serve as an inspiration for this.

**Table 1**  
**Three overall robustness indicators in the risk assessment**

Project	Initial NPV [mio. EUR]	Short- to medium run risk			long-run risk	Specific
		Average NPV	NPV > 0	high/low upside/ downside risk	Overall indicator	Sensitive to project specific assumptions
P113	-6	23 mio EUR	2 / 3	downside risk: - 1.5 mio		Yes: sensitive to wind/solar mix

Note: Illustrative figures and dependence taken from box 2.

Source: Copenhagen Economics

Based on the project robustness in the short- to medium run, long run, and towards specific assumptions, projects are classified into different overall riskiness-categories, e.g. “low”, “medium” and “high”. This overall riskiness will then become relevant for how to proceed with each project (see chapter 3).

### 2.2.3 For large investments, conduct a fuller sensitivity analysis

For the largest investments, such as HVDC corridors, we suggest that the thorough CBA assessment is supplemented with a full sensitivity analysis on key parameters. While there should always be a practical balancing of the value of producing additional information against the costs of obtaining it, it will be valuable in order to avoid stranded assets to illustrate to what extent the business case of a large investment is dependent on specific risks.

The list of sensitivities to take into account could change for different projects and over time. Suggestions to potential sensitivities are:

- Share, mix and location of intermittent renewable energy
- Degree of flexibility in demand
- Innovative grid solutions such as automated systems
- Green transition in neighbouring countries
- EU internal market for electricity

For further meaningful sensitivities, the robustness test conducted for the planned British-Danish HVDC connection “Viking link” can serve as an inspiration, see Box 4. The robustness test came to the result that the Viking link will be a positive business case (positive net present value, NPV) with a likelihood of 88 per cent.

#### **Box 4 The sensitivity analysis conducted for the Viking link**

The Viking link is a planned HVDC submarine power cable between the UK and West-ern Denmark. The construction starts in 2018 and is expected to end in 2022. The Viking link is a cooperation between the British and Danish TSOs, National Grid and Energinet, who have conducted a thorough robustness check. The project's business case was tested for **a range of sensitivities**, namely:

- The value of the Carbon Support Scheme in England is adjusted downwards in 2020
- The Carbon Support Scheme in England continues after 2030
- Changed English product portfolio based on NG scenarios 2030
- Less grid investments in Germany in 2030
- No grid limitations between Western Denmark and Germany in 2030
- Change in demand
- Change in fuel prices 2030
- New connection from England to Germany
- Extreme prices, including negative prices
- Increasing construction costs
- Delayed start of operation
- Longer total time out of operation of the Viking link
- Change in discount rate
- Shorter lifetime

Based on the likelihood of each of those sensitivities as well as their impact on the project's NPV, a **Monte-Carlo-simulation** came to the result that **the Viking link will be a positive business case (NPV > 0) with a likelihood of 88 per cent.**

Source: Energinet (2017) Viking link og 400 kV luftledninger – Business case med færre fortroligholdte oplysninger. Link: <https://energinet.dk/Anlaeg-og-projekter/Business-cases/Business-Case-Vestkystforbindelsen-og-Viking>

## CHAPTER 3

# REFORM PRINCIPLE 3: MORE FLEXIBLE AND COMPREHENSIVE APPROACH TO GRID PLANNING

Electricity grid solutions are large investments with a large share of revenue accruable in a distant and uncertain future. We have particularly in chapter two underlined that realistic variations in the drivers of needed investments are very high. This in turn implies that the economic benefits of individual grid projects must also fall in a relatively large range of outcomes. Some projects will show high economic net benefits under most realistic outcomes while others may have positive benefits only in a very narrow range of outcomes.

In this chapter, we argue first that the current project selection and approval process in the NEP is not sufficiently flexible to take into account this variation between projects (3.1). Second, we argue that the NEP is excessively rigid by requiring extensive and time-consuming calculations for each project every second year, even though the underlying drivers and risks change much less frequent (3.2). Instead, we propose to execute a formal NEP process with a longer cycle of e.g. 4 years, instead of the current 2 years, and to have a rolling monitoring and approval process in between (3.3) In this context, the NEP could also provide valuable input to the overall policy discussion on how to achieve the energy transformation at lower costs (3.4). In the final section (3.5) we discuss how a smooth transition from the current NEP to a new NEP 2.0 can be achieved.

### 3.1 TOO RIGID PROJECT SELECTION AND APPROVAL PROCESS

Currently, a project will enter the project list of the NEP (and be submitted for regulatory approval) if it satisfies the criteria of alleviating a limited number of bottlenecks. This implies that the regulator will be faced with a list of projects potentially with very different socioeconomic values and very different risk profiles. Nonetheless, the regulator is faced with a single decision: either to approve or not. If a project is approved, the respective TSO is legally obliged to implement it.

We argue that this process risks being too rigid and can lead to unwanted outcomes. One potential issue is that if a project is approved based on a scenario assessment that turns out to be incorrect, there will still be a legal obligation for TSOs to build the project. Instead, we suggest that the NEP ranks the suggested projects into different approval categories, based on an assessment of the risks of the projects. This will provide an opportunity to get immediate regulatory approval on the recommended projects, and create a framework that can add flexibility in the subsequent approval process allowing projects that are contingent on a few key developments/risks to be reviewed and subsequently approved if these risks do not materialise.

#### **Recommendation 3.a**

Introduce different approval categories to capture that some decisions should await more information.

When a project is decided, it is important to have a swift implementation process. This requires commitment both from national but also local authorities. To ensure this commitment, we suggest that only projects with a high and robust value for society are recommended for approval; and that once approved, those projects do not have to be re-tested in subsequent NEPs, as it is the case today. Highlighting the “no-regret”-character of those projects, directly recommended for approval, will improve the public acceptance of those projects, and make the subsequent implementation easier. Projects more susceptible to changes on the other hand are not directly recommended for approval, but instead undergo yearly reviews. This proposal should also be seen in line with our recommendation for a change in the cycle and content of NEP as explained below.

### **3.2 THE TWO-YEAR CYCLE RISKS LEADING TO INEFFICIENT OUTCOMES**

The NEP process is currently conducted in a two-year cycle. This process includes significant effort being exerted within quite narrow periods. These efforts are in particular linked to developing consistent scenarios, running market dispatch models, running very detailed grid models, and conducting public consultations by TSOs and by the public. We argue that the additional value added of having this relatively short cycle for such a large process might be small. For example, two sequential NEPs will typically focus on the same base-year for the scenarios, implying that significant effort will go into re-doing the entire NEP process, even though most assumptions and variables are likely to remain the same since the last NEP. Instead, this effort could be used to produce higher-value information to support the investment decisions for particular grid projects such as the suggested net present value calculations and the risk/robustness assessment. This would also eliminate the need to re-assess at short intervals the value of already approved projects in future NEPs, which is the current practice.

At the same time, it is important to maintain a flexible decision making process, where good investment projects can be approved without having to await a decision point several years in the future. Hence, we recommend a solution where the cycle for the formal NEP process is increased to 4 years to ensure sufficient efforts into providing a high-quality investment decision, supplemented by a yearly or semi-yearly review of projects close to approval.<sup>25</sup>

#### **Recommendation 3.b**

Replace the 2-year NEP cycle with a 4-year cycle supplemented with a yearly or semi-yearly review of projects close to approval.

### **3.3 GUIDELINES FOR PRACTICAL IMPLEMENTATION**

Within the framework of a 4-year NEP cycle supplemented with a yearly or semi-yearly review, we propose the following practical implementation:

1. Classify the recommended projects in different ‘risk’-categories
2. Conduct yearly or semi-yearly review and approval of projects on the ‘monitoring list’

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<sup>25</sup> Compliance with EU rules should be checked in detail.

### 3.3.1 Classify the recommended projects in different ‘risk’-categories

In the current NEP, all projects are grouped in the same category, with relatively little information to inform the subsequent approval process. We suggest introducing the following categorisation of projects:

1. *Approval list.* These ‘no-regret’ projects come with the strongest recommendation from the TSOs and they are submitted for immediate approval. Once approved, these projects should obtain full commitment from both national and local authorities, and would not need to undergo a re-assessment in the following NEP.
2. *Monitoring list.* The remaining identified projects will go into the ‘monitoring list’ and can be grouped into the following classification:
  - A. *Close to approval:* These projects are deemed highly likely, but depend on e.g. whether key risks are likely to materialise. Regulator can make a ‘pre-approval’ of these projects under certain conditions, such that they can smoothly be approved in between NEPs if the risks do not seem to materialise.
  - B. *Likely projects for the future:* These projects are likely to be needed going forward, but certain developments need to be confirmed before approval. These projects could also be approved between NEPs, but only if the development looks significantly different from what was expected
  - C. *Potential projects for the future:* These projects will only be needed in the short/medium run under special circumstances. These projects do not need to be reviewed yearly, unless special circumstances occur that will improve the business case of these projects.

### 3.3.2 Conduct yearly or semi-yearly review and approval of projects on the ‘monitoring list’

The prolonging of the full-fledged NEP process should be complemented by a lighter project review, either yearly or semi-yearly. In this review, TSOs would do a stock tacking on developments in key variables and parameters affecting the viability of grid investments. Based on this stock taking, projects in the monitoring list should be re-assessed in order to determine whether key risks have become more or less likely to materialise. If slow developments in alternative solutions (e.g. storage technologies) suggest that an ambitious grid scenario has become more likely, then some projects could be sent for ‘fast track’ regulatory approval. This stock-tacking assessment could e.g. be done just for the projects in category A: ‘Close to approval’.

In practice, this ‘stock-tacking’ could be a relatively simple mapping of the expected development in project specific variables to scenarios, that will enable TSOs to judge whether some scenarios now are more likely than other scenarios. In addition to the ‘project specific risks’ identified in Chapter 2,<sup>26</sup> other key variables to review could be:

- Maturity of key technologies as storage and innovative grid solutions
- Share, mix, and location of intermittent renewable energy
- Degree of flexibility in demand

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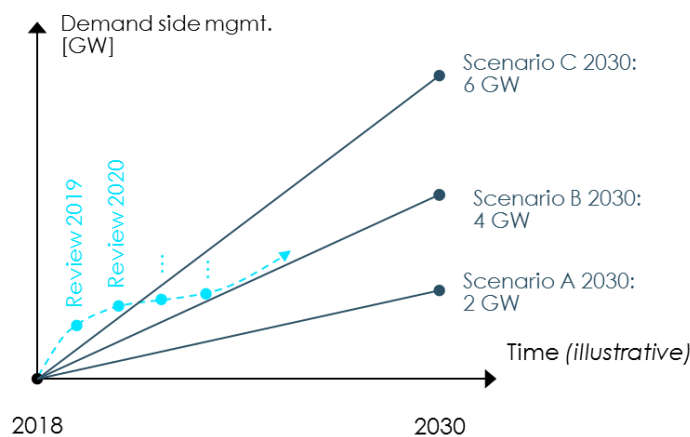
<sup>26</sup> That is, potential key drivers of developments that is likely to significantly affect the business case of a particular project such as e.g. whether an expected data center location takes place or not.

- Green transition in neighbouring countries
- EU internal market for electricity

As a practical example, consider demand side management. The three current NEP scenarios assume that there could be 2, 4 or 6 GW demand side management respectively in 2030. Our suggested review would involve assessing how demand side management develops year for year; in other words: which of the three paths towards 2, 4 or 6 GW in 2030 is the development closest to? Monitoring the development will show whether there is a higher likelihood of one scenario materialising over the other.

In our fictive example (see Figure 8) demand side management develops quickly in 2019 and 2020, being even above the path to the most optimistic scenario C. In the following years, the development slows down, and the actual deployment of demand side management is closer to the path to scenario B – but still far away from the path to scenario C. Concretely, this could mean that if a grid project’s viability is only given in scenario A, but not B or C, then this project would move downwards on the monitoring list into classification C (potential projects for the future), and would not be close to being suggested for approval. A different development of demand side management however, for example an actual deployment close to or even below the path to scenario C, could mean that the projects moves up on the monitoring list towards classification A (close to approval).

**Figure 8**  
**Regular reviews can support the project risk assessment**



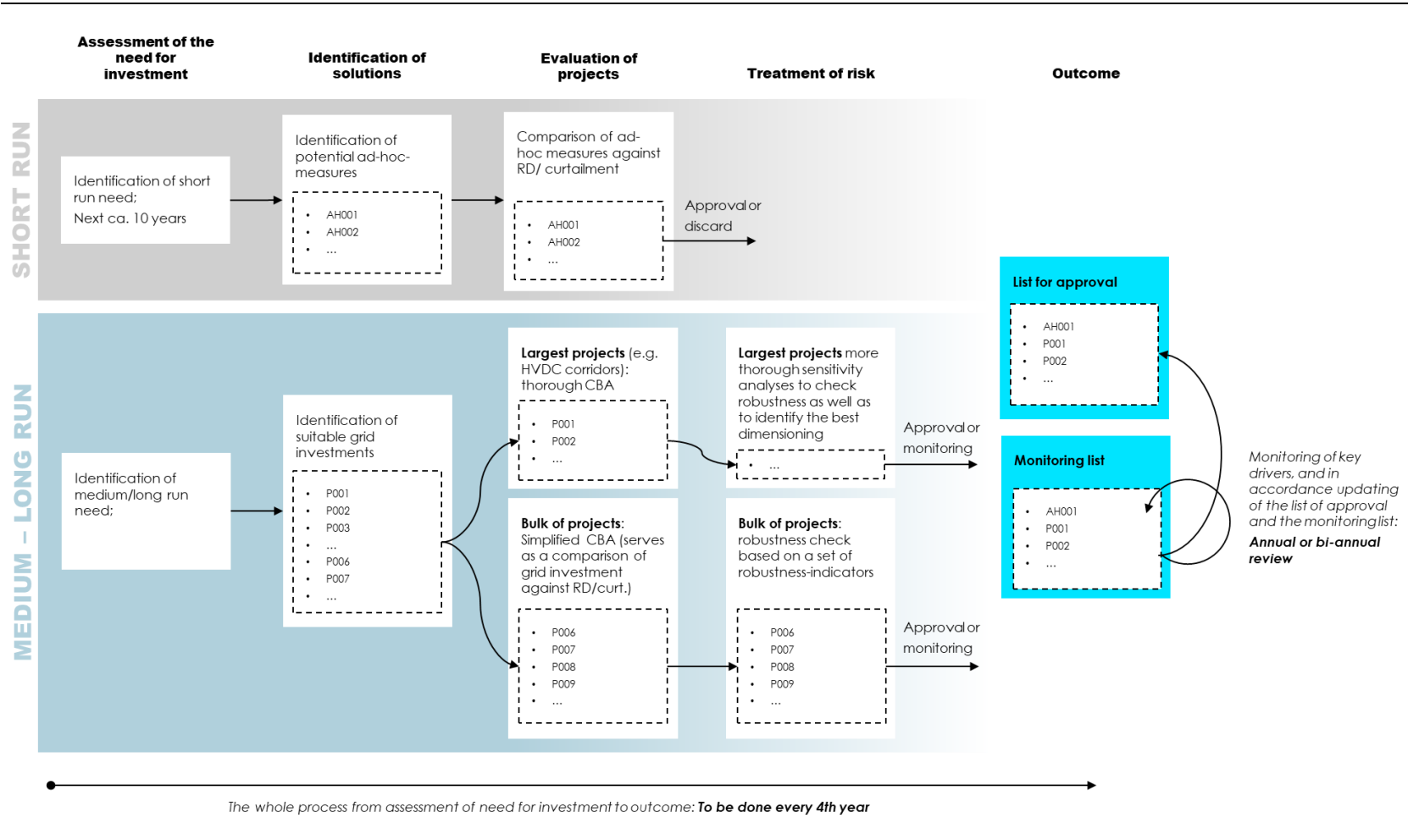
Source: Copenhagen Economics

This assessment could be done not only for demand side management, but for the full list of variables to deliver a complete picture of whether Germany is moving towards a situation where more grid is needed or where less grid is needed.

The recommendations and suggestions for the practical implementation we make throughout the chapters 1 to 3 are highly interlinked. The outcomes of each element of the process form the input for the next element. Figure 9 shows an overview of the full process. Grid planning starts with an assessment of the need for investment, on which basis solutions are identified – both for the short-

and medium- to long term (see chapter 1). The identified solutions – ad-hoc measures or grid projects – are evaluated regarding their value to society; for the bulk of projects, this evaluation can be a pragmatic cost-benefit-assessment, while for the largest projects, the assessment should be more thorough. The same holds for the risk assessment which follows after, and which tests the outcome of the cost-benefit assessment – the net present value – for its robustness in different scenarios (see chapter 2). Projects with a high and robust value to society are ‘no-regret’-projects, and should be recommended for approval directly. Projects whose value or robustness is not sufficiently certain should not be on the *monitoring list*, and suggested for approval only if the development of key variables materialises in favour of the particular project – in other words, only if they turn out as good investments for society.

**Figure 9**  
**Outline of full process of the implementation principles**



Source: Copenhagen Economics

### 3.4 THE NEP AS AN INPUT TO WIDER ENERGY POLICY

We have proposed a reformed NEP with a stronger focus on a cost-benefit approach to grid investments in a longer term perspective and more focused approach on the key drivers that may drive variation in grid investment costs in the decades ahead. This could help to identify the investment projects that are economically most robust to alternative plausible scenarios and also review the scope for alternative to grid investments in the short and longer term.

This approach could also provide valuable input and feedback to the wider energy policy debate. By clarifying the costs-and-benefits in a longer perspective, it can also help policy makers to understand what actions that could be taken to reduce the costs of the energy transformation. This applies to a broad spectrum of policy choices:

- What is the scope of new technologies to increase the flexibility of energy markets, what are the barriers to make them more mature and scalable and what role do TSO and other stakeholders have to advance their progress?
- What roles could improvement in market design play to smooth fluctuations in power market prices?
- What role does the expansion and location of new capacity of installed intermittent energy source play for the needs for grid expansion?

The basic point is that a reformed NEP could provide a strong and transparent framework for policy choices affecting energy supply and demand in the German electricity system including not the least grid investment needs.

#### **Recommendation 3.c**

The NEP and its calculations and modelling work should serve as input and feedback to the wider energy policy debate.

### 3.5 THE TRANSITION: FROM THE CURRENT NEP TO A NEW NEP 2.0

As noted earlier in this report, the NEP 2030 has allowed a major and needed expansion of the grid system to take place. It is important that the transition to a new NEP does not jeopardize the progress already reached nor derail the investment projects in place and being rolled out in the coming years.

In this context, we suggest to continue as planned with the NEP that is currently already in the first phases of preparation. This study is supposed to serve as input for a discussion between the TSOs and the regulator. Going into 2019, this discussion should be translated into an agreement on the principles as well as legal ramifications and operational consequences of this new agreement. On this basis, the TSO could early in 2020 release the first scenario framework for an NEP 2.0.<sup>27</sup> In this context, we would highlight the need also to work on the wider energy policy issues that impact on the need for grid investments in particular the need to push measures that improve the flexibility of the energy system, as we have discussed in earlier chapters of this study.

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<sup>27</sup> The TSOs could potentially consider some of the recommendations made in this study already in the next NEP (NEP 2030, 2019 version), when they identify and later present to the regulator the need for new grid investments.

The implementation of the recommendations made in this study will entail changes in the processes around the NEP. Those changes are needed on different levels. Some can be initiated by the TSOs, then discussed with the regulator and agreed on in the near future. For other changes, adjustments in the legal basis will be necessary. The four general levels of changes are:

- TSOs
- Regulator (BnetzA / BMWi)
- German legislation
- EU legislation

An initial assessment indicates that the implementation of the recommendations of this study are likely to be in line with EU legislation. Changes will be necessary regarding the German legislation as well as in the approach towards grid planning and the internal processes at TSO- and regulator-level.

We find for example that for the TSOs to be able to make use of cost-benefit principles and a net-present-value approach (recommendations 1.a, 1.c), *mainly coordination between the TSOs and the regulator is needed* to agree on the respective changes in internal processes; legal adjustments are not necessary. Similarly, the projects submitted to the regulator for approval can be assigned to different approval categories such as the list for approval and the monitoring list (recommendation 3.a). Also, the regulator can approve projects conditionally to certain developments.<sup>28</sup>

For the implementation of a range of other recommendations however, legal adjustments are likely to be necessary, mostly in the German Energy Act (EnWG) or the Renewable Energy Sources Act (EEG). This applies for example for using long-term scenarios (recommendation 2.a), for which, according to a first assessment, a change in the period of observation (§ 12a paragraph 1 sentence 2 EnWG) will be necessary. Also, the 2-year-cycle of the NEP has a legal foundation, which might need to be changed to implement recommendation 3.b which suggests a 4-year-cycle.

In addition, there are some recommendations that do not contradict the legal foundation per se but may still require changes in the practical implementation of the legal foundation. One of those cases is the recommendation that the NEP should be able to consider ad-hoc-measures as solutions (recommendation 1.d). Ad-hoc measures are sometimes considered already today, however, the legally anchored period of observation complicates proving the benefits of such measures. Another example is the prioritisation of projects based on cost-benefit principles (recommendation 1.a). In general, there is no law that would prohibit the use of such principles. However, the EEG commands that all electricity from renewable sources must be purchased, transmitted and distributed. As soon as the prioritisation of projects based on cost-benefit principles contradicts those rules, the latter must be adjusted.

Table 2 provides an overview of which adjustments will be needed for the implementation of each of the recommendations.

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<sup>28</sup> The regulator has used this opportunity before. The BNetzA has for example handed out conditional approvals within the O-NEP process (offshore grid connections for DolWin4 (NOR-3-2) and NOR-7-2 (BorWin6)).

**Table 2**  
**Needed changes and their level for the implementation of the study's recommendations**

RECOMMENDATION	DESCRIPTION OF NEEDED CHANGES	LEVEL OF CHANGE
1.a - Use transparent cost-benefit principles as the main prioritisation criterion for determining the need for new grid projects instead of the 'bottleneck-free grid'	The EnWG commands the TSOs to manage the transmission grids efficiently. Cost-benefit principles can be used as long as TSOs can, in the cases where they do not pursue certain measures, prove that this does not hamper reliable grid operations. However, the EEG commands that all electricity from renewable sources must be purchased, transmitted and distributed, which means adjustments in the EEG are necessary.	TSOs; German legislation (esp. EEG)
1.b - If it is best for society to alleviate a bottleneck through redispatch and curtailment, do so – and do not build additional grid projects.	Curtailment is a so-called ultima-ratio-measure. To utilize curtailment as a (planned) tool to alleviate bottlenecks, a structured process for this needs to be established. The legal framework for the solution of urgent bottlenecks are the §§13,14 EnWG and §§ 11,14 EEG.	German legislation (esp. EnWG, EEG)
1.c - Use a net-present value approach that takes costs and benefits over the full lifetime into account.	Neither legal nor regulatory obstacles hinder the use of a net present value approach, see recommendation 1.a	TSOs
1.d - The NEP process should be capable of considering ad hoc measures as solutions.	The opportunity to consider ad-hoc measures is given through the EnWG §12b para. 1 sentence 4 Nr. 3. However, there are two obstacles when it comes to the practical implementation: <i>Firstly</i> , the benefits of ad-hoc measures often occur in the short term, which means that the benefits are underestimated when looking at a target year 10-15 years in the future. This complicates proving in the NEP that ad-hoc measures are reasonable and beneficial. Adjustments of the period of observation (§ 12a para. 1 sentence 4 Nr. 3) could potentially be a solution to this issue. A short-term analysis could for example be added to the long-term planning. <i>Secondly</i> , the NEP process is rather lengthy: several years pass from the identification of a ad-hoc measure as a solution through its approval to the actual construction. A large share of the benefits can then already be lost. A potential solution could be to treat ad-hoc measures separately (outside the NEP) and to ensure a quick approval. The basis for such a change would be the EnWG.	German legislation (esp. EnWG)
2 – (shortened) Conduct illustrative long-term scenarios, highlighting risks and opportunities and their implication for investment needs.	This requires an adjustment of the period of observation, currently set to 10-15 years in § 12a paragraph 1 sentence 2 EnWG	German legislation (esp. EnWG)

RECOMMENDATION	DESCRIPTION OF NEEDED CHANGES	LEVEL OF CHANGE
3.a - Introduce different approval categories to capture that some decisions should await more information.	No legal adjustments needed. The BNetzA already has the right to determine content and process of the NEP following the EnWG § 12c para. 7 and § 29 para. 1. The TSOs can define different categories, and the BNetzA can show interest and utilize that information, for example through making conditional approvals. Such processes should be discussed and coordinated between the TSOs and the regulator.	TSOs + BNetzA
3.b - Replace the 2-year NEP cycle with a 4-year cycle supplemented with a yearly or semi-yearly review of projects close to approval	Adjustments needed in § 12a EnWG, where the cycle needs to be changed from 2 years to 4 years. In addition, EU legislation (Nr. 1228/2003, article 12 para. 1) commands the TSOs to publish an investment plan every 2 years. However, the annual or bi-annual monitoring that we suggest in this study could probably be designed in a way that it meets the EU requirements. The main NEP can therewith be prepared each 4 years without legal adjustments on EU level.	German legislation (esp. EnWG)
3.c - The NEP and its calculations and modelling work should serve as input and feedback to the wider energy policy debate.	No legal adjustments required. The creation of a regular, well-established, respected dialog and knowledge sharing requires coordination and initiative from both TSOs and BMWi.	TSOs + BMWi

Note: This is to be understood as a first assessment. No claim is made to completeness.

Source: Copenhagen Economics in collaboration with experts from TenneT

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Key literature have been all relevant NEP documents published by the four German TSOs (50hertz, Amprion, TenneT and TransnetBW) and the BNetzA, as well as legislative documents. Such relevant documents are for example the current as well as older NEPs and their attachments, scenario frameworks, cost estimates, approval documents, results of the consultation process, guidelines, environmental impact assessments and so forth. The legislation considered is mainly the EnLAG, EnWG, NABEG, BBPIG, UVPG, EEG, BImSchG and ARegV.

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