ACTIVE NETWORK MANAGEMENT: TECHNICAL AND FINANCIAL ASPECTS

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EXECUTIVE SUMMARY

Enabling the integration of massive amount of renewables – RES – in distribution grids with the agility required to meet international climate goals, we need to consider alternative network development solutions.

The European research project Active Network Management For All – ANM4L – has been addressing solutions to increase the utilisation of existing grid assets while maintaining the security of supply. The ANM4L project has considered how to prevent overloading and overvoltage situations in distribution grids, explicitly when originating from increased levels of distributed RES.

Coordinated by RISE Research Institutes of Sweden, the ANM4L project has been an international cooperation, from December 2019 to November 2022, with a consortium comprising: Lund University (SE), RWTH Aachen (DE), Lumenaza (DE), E.ON Eldistribution (SE), E.ON Észak-dunántúli Áramhálózati (HU), E.ON Group Innovation (DE), and the Municipality of Borgholm (SE). The developments in the ANM4L project have been gathered around three pillars: 1st Control solutions, 2nd Business solutions, 3rd ICT solutions. These pillars collectively resulted in a developed toolbox to support operation & planning of distribution grids. The functionality and replicability of developed solutions have been tested and demonstrated in Sweden and Hungary.

The report consists of outcomes from the research pillars Control and Business solutions. The research, which has focused on the technical and financial aspects of Active Network Management, presented in this report gathers results from several of the project deliverables and publications.

CONTENT

LIST OF ABBREVIATIONS

ANM	Active network management
BAU	Business-as-usual
BESS	Battery Energy Storage Systems
BRP	Balance responsible party
CAPEX	Capital expenditure
CBA	Cost-benefit analysis
DG	Distributed Generation
DLR	Dynamic Line Rating
DR	Demand Response
DSM	Demand Side Management
DSO	Distribution system operator
ICT	Information and communications technology
IRR	Internal rate of return
MC	Marginal Cost
NLTC	No-load Tap Changer
NPV	Net present value
O&M	Operations and maintenance
OLTC	On-load Tap Changer
OPEX	Operating expenditure
PV	Photovoltaic
RES	Renewable Energy Source
STATCOM	Static Compensator
SVC	Static Var Compensator
TOTEX	Total expenditure
TSO	Transmission system operator
WACC	Weighted average cost of capital
WTG	Wind Turbine Generator

DEFINITIONS

Active Network Management ANM	The exploitation of flexible network assets for the purpose of providing secure means of increasing grid utilisation.
ANM solution	The concept of a control system, integrated with ICT and the power system, with the ability to manage generation, load and electrical tolerances for DSO-driven purposes.
Flexible network assets	Assets in the grid (load, production, and other controllable equipment) with the ability of being controlled to support grid needs
Power transfer capacity	The ability of the grid (cables, lines, transformers, etc.) to transfer electricity between generation and demand. The power transfer capacity has physical limitations (thermal and stability) and limitations based on standards (power quality) and protection settings.
Demand Side Management DSM	The control of flexible resources performed directly by the DSO for operational network security purposes.
Demand Response DR	The control of flexible resources performed via market procurement (e.g., direct from supplier or via aggregators), not directly controlled by the DSO itself as it would cause market distortions.

INTRODUCTION

In this report, we have gathered some of the main outcomes of the European research project ANM4L - Active Network Management for All[1].

The main goal of the ANM4L project was to demonstrate how active network management (ANM) solutions can effectively and efficiently increase the integration of renewables in the distribution network, thanks to innovative tools and approaches.

The report consists of outcomes from two of the project's main research pillars: Control and Business solutions. This research focused on technical and financial aspects of ANM, where the combined efforts of Lund University and RISE Research Institutes of Sweden were reported in several project deliverables which are collected and published in this report. The report is structured as follows:

> Chapter 1 presents the financial values of ANM from a utility perspective, illustrating the principles of cost-benefit analysis for ANM, addressing long- and short-term financial values and risks.
>
> Chapter 2 presents the technical ANM capabilities, considering control solutions for active and reactive power regulation, in situations with voltage and current limitations in the distribution grid.
>
> In Chapter 3, generation, load, grid equipment, and flexibility enabling technologies, are categorised by their technical abilities and financial impact of being utilised as ANM resources.
>
> Chapter 4 presents the regulatory aspects, and the impact that regulation has on the ability to implement or utilise ANM solutions.
>
> Chapter 5 presents an evaluation of ANM solutions based on a case study, addressing the technical control needs and the resulting financial impact.
>
> Chapter 6 provides a summary of the technical aspects of ANM and their impact on operation and planning of the power system, and related technical and financial risks.

This report covers previously unpublished material, thus supplementing the ANM4L project final results presented in [1] and [2]. The publication of this report concludes the ANM4L project, following the successful PhD defence of Martin Lundberg on "Grid Capacity: Challenges and Opportunities" [3].

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[1] The ANM4L project was carried out between 2019 and 2022, supported by the EU H2020 grant agreement No 775970 through the ERA-Net SES initiative.

CHAPTER 1: VALUE OF FLEXIBILITY FOR UTILITIES

(ANM4L DELIVERABLE D4.1)

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1. BACKGROUND

1.1. The European electricity market context

The regulatory frameworks and overall market designs of Europe's electricity markets have in recent decades slowly converged. Significant differences between European countries still remain, but it is nevertheless possible to identify electricity market features that are common across most EU member states. This is partly a result of several EU regulations and directives, not least the Third Energy Package of 2009 [4], with recent updates as part of the 2019 Clean Energy Package [5]. For example, the Third Energy Package established minimum requirements for EU Member States regarding unbundling (see section 1.1.1 below), while the Clean Energy Package provides common rules regarding, for example, consumer rights.

1.1.1. Unbundling requirements

The European electricity market structure is based on an unbundled principle, whereby activities related to transmission and distribution are separated from activities related to generation and supply (where supply refers to the sale of electricity to end-users). For transmission and distribution activities, the natural monopoly aspect of electricity grid infrastructure means that competition is neither likely to arise spontaneously nor likely to be economically efficient. Therefore, these activities are conducted within companies that are awarded explicit concessions to operate said monopolies under the regulatory constraints stipulated by national regulators.

However, activities related to generation and supply can be conducted in a liberalized and competitive market. To promote a level playing-field whereby market participants are given access to the grid infrastructure on equal terms, unbundling regulations have been implemented aiming to ensure the independence of companies engaged in transmission and distribution from generation or supply interests.

The EU regulatory requirements regarding unbundling are different for TSOs and DSOs. For TSOs, the requirements are relatively strict with full ownership unbundling being the preferred approach. For DSOs, the EU requirements are less far-reaching, in the sense that it does not require unbundling in terms of ownership, i.e. the DSO may be part of a larger vertically integrated undertaking. For larger DSOs (more than 100 000 connected customers), unbundling is required in terms of legal form, organization, and decision making. For smaller DSOs, the EU directives only require unbundling of accounts for the distribution activities. However, some European countries have chosen to implement stricter unbundling requirements also for smaller DSOs.

1.1.2. Zonal trading

Trading of electricity between generators and suppliers take place both bilaterally and on auction-based marketplaces, with the former being more common in countries such as Germany and the UK while the latter dominates in, for example, the Nordics and Italy [6]. Irrespective of whether trading takes place bilaterally or on an auction-based marketplace, the trading is based on a zonal model where it is assumed that electricity can be delivered without any network constrains as long as buyer and seller are in the same bidding zone.

For example, Sweden is subdivided into four bidding zones. If two market participants are located within the same bidding zone, then it is assumed that sufficient network capacity will be available to handle the resulting power flows. If network limitations nevertheless arise within a zone, then the TSO is responsible for managing the situation using, for example, countertrading. The TSOs are also responsible for determining the cross-zonal capacities that should be made available to the market for transfers across zonal borders.

1.1.3. Financial regulation of DSOs

As noted above, because of the monopoly status of DSOs, their revenues and/or tariffs need to be regulated. Regulation is needed to ensure controlled pricing, efficient investment and non-discriminatory access and tariffs. The objectives of these regulations are therefore to ensure reasonable prices and availability for all customers, whilst also ensuring long-term supply quality, encompassing supply security, safety and infrastructure health.

Many different methods exist for how such a regulation can be carried out. The most commonly used regulatory approach in Europe is to use a revenue cap [7]. This means that the regulator specifies a cap for the total revenues that the DSO is allowed to collect from its customers but allows the DSO some flexibility in how the tariffs should be specified. The calculation of the revenue cap is typically based on a specification of a regulatory asset base, consisting of the assets that the DSO should be allowed a regulated financial return on. The valuation of the asset base is in some countries made based on the actual historical cost of the investments, and in other countries based on an estimated re-investment cost.

Instead of a revenue cap approach, some European countries use other regulatory models, such as where the regulator directly specify the tariffs. Furthermore, even though many European countries use some form of revenue cap, there are still significant differences between countries in terms of how the revenue cap is calculated. A relatively detailed comparison between different European countries is provided in [7], and a theoretical discussion of pros and cons of various approaches can be found in [8]. Task 4.3 of the ANM4L project plans to analyse financial regulations and their consequences for ANM in more detail.

1.2. ANM and flexibility in distribution networks

Traditionally, most distribution networks are planned and operated in a relatively passive way, in the sense that the physical network infrastructure is dimensioned to handle power flows that can be reasonably expected. This has been necessary, since DSOs generally do not have the ability to control power flows in real time. The development of high bandwidth communication solutions is changing the way grids can be operated allowing for more accurate prognosis data and remote control of grid infrastructures. Thus, the potential for active management is increasing.

An increased penetration of distributed generation, as well as new loads from e.g. electric vehicles, create new power flow patterns in distribution networks. With the traditional approach to network planning, this could necessitate costly investments in physical network reinforcements. However, alternative solutions, where DSOs take a more active role in monitoring and controlling distribution networks, are increasingly being suggested (see, for example, [9]). Within the ANM4L project, the term active network management (ANM) is used to capture these types of alternative solutions. The ANM4L project uses the following definition of ANM:

> ***ANM is the exploitation of flexible network assets for the purpose of providing secure means of increasing grid utilization.***

There are many different potential types of flexible network assets, such as demand response, distributed generation and battery energy storage systems. There are also different types of network issues for which ANM can be useful, such as for controlling voltage or avoiding overloading.

In many cases, the DSO does not own the flexible asset that could be used for an ANM solution. In such cases the DSO may need to compensate the owner for allowing the DSO to control the asset, especially if such action could lead to increased costs, lost revenues or some other inconvenience for the asset owner. For this reason, several research projects and commercial initiatives around Europe are developing and implementing flexibility markets where DSOs can procure flexibility services from assets in their networks. Examples include the PicloFlex marketplace in the UK [10], the NODES market concept [11] and the CoordiNet project [12].

The proposed flexibility markets differ substantially in terms of market design and functionality. For example, some include continuous short-term trading for activation of the flexibility assets, whereas others rely on long-term agreements. Furthermore, some have a narrow DSO focus whereas others attempt to create marketplaces where the flexibility can be made accessible also to other participants, such as TSOs.

2. COST-BENEFIT ANALYSIS IN AN ANM SETTING

The central question regarding the value of ANM for long-term planning is “Should an ANM solution be invested in?”. The answer to this question depends on what other options are available to the DSO. Estimating the value of ANM for long-term planning is therefore a matter of comparing the costs and benefits that are expected to arise if the ANM solution is used, to the costs and benefits that are expected under an alternative approach without ANM.

The cost-benefit analysis (CBA) approach is an often-used framework for conducting structured comparisons between investment options. In this report, we discuss how a cost-benefit analysis can be performed in an ANM setting. Although the CBA framework discussed in this report is general and could be applied in a wide range of situations, it is nevertheless useful to present the framework using a more specific example. The main setup for this example is presented here, with additional details provided later, in section 0. This example is entirely fictional and is not based on any actual DSO or location.

The example used in this report focuses on a case where a DSO operates a network in an area where the amount of distributed generation is large relative to the local network capacity. Therefore, the DSO finds it challenging to accept new generation connections in the area. To enable new connections without jeopardizing security of supply, the DSO needs to consider options for how to increase the capacity of the network.

The traditional method for such capacity expansions would be to invest in higher-capacity physical network infrastructure. This could, for example, involve installing higher-capacity transformers or upgrading distribution lines. However, for the discussions in this report, it is assumed that an alternative to traditional infrastructure reinforcements is available in the form of an ANM solution. Such ANM solutions could, for example, involve procurement of flexibility services from local flexibility assets such as flexible load, energy storage or generation resources.

The purpose of the CBA method discussed in this report is to estimate the value of such an ANM solution by comparing it to the traditional reinforcements that otherwise would have been needed.

Although the discussions in this report focus on a case with excess generation in a local network, the same general principles would apply for the reverse case with load demand exceeding the network capacity. The methods discussed here could therefore be applied in either of these situations.

2.1. Specification of scenarios

CBA is often used in either one of the following two settings: either for determining whether a particular investment should be made or not, or for comparing a set of investment options against each other. Either way, it is important to precisely define both the investment options of interest and appropriate counterfactual scenarios that the investment options are to be compared against.

For the ANM setting, either of these two options can be pursued. With the first approach, an investment option that includes an ANM solution is directly compared to a traditional reinforcement option without ANM, implicitly assuming that business-as-usual (doing no major investment at all) is not a viable option. Alternatively, a business-as-usual scenario can be defined, and the two investment approaches can be evaluated compared to the business-as-usual scenario. In the following, we focus on the second approach since this provides greater transparency regarding the costs and benefits that are attributable to the two investment options and allows for greater flexibility in expanding the analysis to cover additional investment alternatives.

Therefore, to perform the CBA analysis discussed in this report, (at least) the following three scenarios need to be specified:

- A business-as-usual scenario where investments are kept at a minimum (*the BAU case*).
- A scenario where investments are made in traditional network reinforcements (*the reinforcement case*).
- A scenario where an ANM solution is implemented (*the ANM case*).

2.2. CBA from whose perspective?

Cost-benefit analyses differ depending on the perspective taken in the analysis. Following the terminology in [13], two main types of CBA can be identified:

- **Financial CBA**: This type of CBA compares costs and benefits from the perspective of a single entity (such as a DSO), analysing if the benefits enjoyed by the entity outweighs the costs incurred by the entity.
- **Economic CBA**: This type of CBA compares costs and benefits from a broader societal perspective, analysing if the benefits enjoyed by society as a whole exceeds the costs incurred by society as a whole.

In our ANM setting, a financial CBA can be carried out from a DSO perspective, aiming to answer the question "Would it be beneficial for the DSO to invest in an ANM solution?". An economic CBA takes a broader societal perspective, aiming at answering "Would it be beneficial for society as a whole if the DSO invested in an ANM solution?".

Since DSOs are regulated monopolies, the financial CBA from a DSO perspective is influenced by the regulatory model that govern DSO revenues and profits. Therefore, the financial CBA needs to take the regulatory model into account.

In this report, both of these approaches (economic CBA and financial CBA) are considered and compared. This is especially interesting from a regulatory perspective, since it can help shed light on how a particular regulatory model brings the outcome of the financial CBA closer to or further away from the outcome of the economic CBA. Figure 1 provides an overview of how the three cases and the two CBA approaches relate to each other.

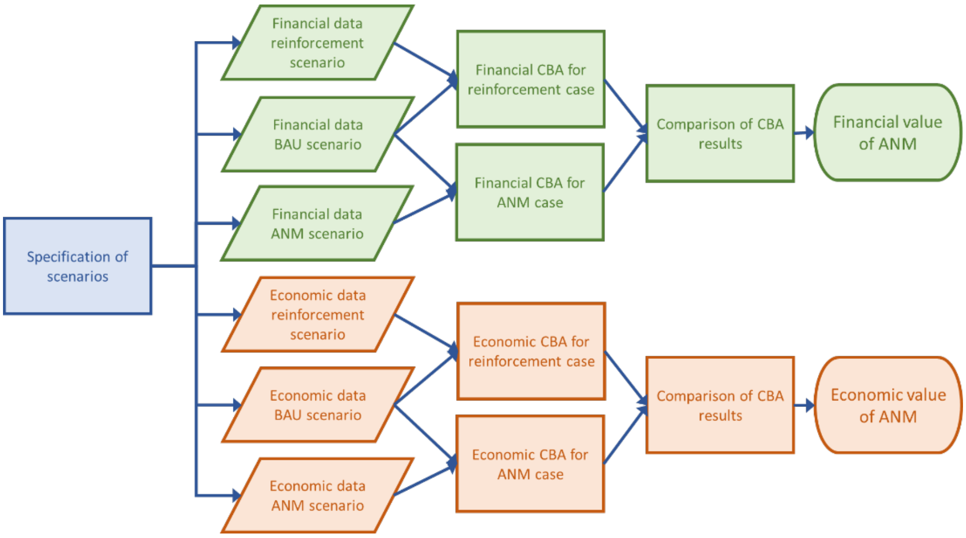

Figure 1 Overview of CBA methodology described in this report

3. GENERAL PRINCIPLES OF COST-BENEFIT ANALYSIS

The basic idea behind cost-benefit analysis (CBA) is simple and intuitive: by assessing costs and benefits of various investment options in a structured way, the option with the highest net benefits can be identified. However, even if the basic idea is simple, performing CBA in practice can be very challenging. For example, CBA often involves making forecasts of costs and benefits far into the future, placing monetary values on non-traded goods or services, comparing costs and benefits that arise at different points in time, accounting for risk and uncertainty, and so on. This section briefly discusses some general considerations regarding CBA and how they relate to the ANM setting considered in this report.

3.1. Which items to include?

CBAs are based on an incremental approach. This means that costs and benefits of a particular investment case are valued relative to some without-the-project counterfactual case [13]. In this report, the business-as-usual case is used as a common counterfactual, against which both the traditional reinforcement case and the AMN case is evaluated. Therefore, only costs and benefits that differ between at least two of these cases need to be included in the analysis.

The list of factors that potentially could be affected by an investment can often be made very long, especially for an economic CBA. In theory, a CBA should include all such items. In practice, it is often impossible or prohibitively time-consuming to analyse all possible costs and benefits. Therefore, only those factors that are likely to be large enough to significantly alter the conclusions of the analysis should be included [14].

3.2. All values expressed in monetary terms

To enable a quantitative comparison between all relevant costs and benefits, they must all be measured in the same unit. This typically means that monetary values need to be provided for all costs and benefits that are included in the CBA analysis.

However, this *does not* mean that CBAs need to be limited to costs and benefits where money actually changes hands. Especially for economic CBA, all types of relevant costs and benefits should be included, irrespectively of whether anyone actually pays for them or not. Examples of non-traded items that can be included in an economic CBA are the cost of environmental damage, the value of additional leisure time, the value of good health, or the cost of noise exposure. In an ANM context, non-traded items could include, for example, security of supply or the visual impact of overhead lines.

Obviously, it can be very challenging to find good and objective valuation estimates for non-traded items. Some CBA guidelines (such as [15]) therefore suggest that difficult-to-quantify items should be left out of the quantitative CBA analysis and instead analysed qualitatively. However, when time comes for choosing between the investment options, the decision-maker will need to weigh the value of the qualitatively assessed items against the ones that has been quantified. In doing so, the decision-maker implicitly makes a quantification of the value, but in a much less transparent way. Therefore, it is often suggested [16] that CBAs should attempt to quantify costs and benefits in monetary terms as far as possible.

3.3. Time and discounting

Irrespective of the type of CBA, it is often necessary to make comparisons between costs and benefits that arise at different points in time. There are two slightly different – but closely related – methods commonly used for this purpose: the net present value (NPV) method and the internal rate of return (IRR) method.

With the NPV method, all future costs and benefits are discounted to a present value using a pre-determined discount rate. This can be expressed as:

$$NPV = \sum_{t=1}^{T} \frac{b_t - c_t}{(1+r)^t}$$

where the net present value is calculated based on T time periods (often years), b_t and c_t represent the monetized expected benefits and costs for time-period t, and r is the discount rate. The time horizon T is typically chosen based on the expected lifetime of the investment, and the calculation can be adapted to include end-of-life residual values. While the discount rate could vary over time, it is common practice to assume a fixed discount rate [13].

The choice of an appropriate discount rate, r, is a key decision that can greatly influence the outcome of an NPV calculation. Further, it may be difficult to find objective exact values for the discount rate, necessitating some amount of judgement.

For financial CBAs, the discount rate should reflect the opportunity cost of capital, taking the riskiness of the investment into account. It should therefore represent the return on investment that the firm could get if it invested in an alternative project with a similar risk profile. In practice, it is common to use the firm's weighted average cost of capital (WACC) for this purpose, although this may need to be adjusted to capture the risk profile of the investment.

For an economic CBA, a social discount rate should be used. The theoretical underpinnings for what such a discount rate should reflect is a somewhat controversial topic with ethical questions at its core [17]. Common approaches include the social rate of time preference method and the social opportunity cost of capital method [18].

The IRR method is similar to the NPV method, but instead of specifying a discount rate, one calculates which discount rate that would yield a zero NPV. In other words, the IRR for the project solves the following equation:

$$0 = \sum_{t=1}^{T} \frac{b_t - c_t}{(1 + IRR)^t}$$

Therefore, the IRR can be calculated without first determining a discount rate, which may seem like an advantage for the IRR method. However, the calculated IRR needs to be compared to something, which brings one back to the same discount rate. The IRR method and the NPV method are therefore essentially two different perspectives on the same calculation.

When calculating the NPV or IRR for projects spanning multiple years, it is important to keep inflation in mind. This can be done either by consistently using monetary amounts that reflect the price level at a chosen reference year, irrespectively of when the cost or benefit actually occurs (real valuation). Alternatively, costs and benefits can be valued at a price that reflects the expected price level during the year when they occur (nominal valuation). If the real valuation approach is chosen, then the discount rate must be adjusted accordingly, subtracting an amount equal to the expected yearly inflation rate compared to a nominal discount rate.

To make the calculations in the following illustrative example as simple as possible, real valuation is applied and the assumed discount rates are therefore real discount rates.

3.4. Risk and uncertainty

Performing CBA in practice typically involves estimating values for many different parameters, many of which will be highly uncertain. For a CBA to provide a fair picture of expected net benefits, it is necessary to somehow capture and represent this uncertainty.

A common approach for capturing uncertainty regarding parameter estimates is to simulate net benefits using a Monte Carlo approach, with probability distributions for input parameters rather than point estimates. This can provide a quantification of how uncertain the results of the CBA are, provided that reasonable probability distributions for the input parameters are available. Alternatively, if it is difficult to motivate a particular probability distribution for some key parameters, a sensitivity analysis may be preferable, analysing the sensitivity of the CBA results to changes in some key parameter values.

3.5. How should the results of an economic CBA be interpreted?

While the purpose of a financial CBA is relatively clear – it shows if an investment would financially benefit the relevant entity or not – the purpose of an economic CBA is somewhat less obvious. The idea is that an economic CBA should indicate if a proposed investment would be beneficial for society as a whole. However, from a social fairness perspective, the appropriateness of using economic CBA can be questioned.

Economic CBA is commonly used for evaluating, for example, public investment projects. The idea behind this is that, if the total value for those who benefit from the investment exceeds the total costs, then the investment should be made. While this might sound obvious, it is not clear that such an approach actually leads to appropriate and fair policy decisions. This issue has been a topic of academic debate for almost a century [19].

One of the main points of contention concerns the distributional effects of the investments in question. CBA typically sums up total costs and benefits, disregarding who benefits from the investment and who pays for it. Therefore, even if the total benefits to society outweighs the total costs, there will most likely be individual members of society for whom the costs outweigh the benefits. A simple example is when an infrastructure project provides large benefits to a small region of a country but is paid for by taxpayers across the whole country. In such a case, a CBA may show that the benefits of the project outweigh the costs, while most members of society would be left worse off from the investment.

The traditional argument for nevertheless following a CBA approach when determining the appropriateness of public investments involves some patience: if CBA methods are consistently applied, then most individuals would likely be better off in the long run. However, this requires that investments are distributed somewhat evenly across the population, which may contradict a strict prioritization of investment options purely based on CBA results.

What does this mean for the methodological approach described in this report? The reason for making a comparison between the outcome of a financial CBA and an economic CBA, is to enable an analysis of whether the regulatory regime incentivizes the DSO to make “the right” investments, where the economic CBA is meant to indicate if the investment is “right” or not. However, economic CBA cannot alone be interpreted as providing the final answer to whether an investment is “right” for society. Providing such an answer would require complementing the economic CBA analysis with a judgement that captures society’s preferences regarding, for example, fairness. This limitation of the CBA approach needs to be kept in mind when applying the method described in this report.

4. ILLUSTRATIVE EXAMPLE

In the following, the CBA analysis framework is explained using an illustrative example case. This example case is entirely fictional and is not intended to represent any specific location or DSO. The monetary values used for different cost and benefit components are not based on any actual cost or benefit assessments. The example is also relatively simple; a real application of the CBA framework would likely include a more detailed breakdown of the various costs and benefits.

First, it is assumed that a clearly defined network area has been identified, wherein a large amount of variable renewable generation is installed. For the sake of illustration, it is assumed that there is a lot of wind power in this particular area. The amount of installed wind power has reached a level such that, on windy days, the resulting power flows are approaching the limit of what the local network is dimensioned for.

The DSO has received requests for connecting an additional 30 MW of wind power generation in the area. It is assumed that the DSO is not expecting any further requests after these 30 MW have been installed. Therefore, the problem at hand is to enable the connection of these new wind power connections, after which no further changes are anticipated.

4.1. Description of cases

4.1.1. The BAU case

The BAU case in this illustrative example is a case where the existing network capacity is maintained but not expanded. It is here assumed that this means that the DSO has to decline the requests for new generation connections. Since DSOs are typically required to connect new customers upon request (within a reasonable time-period and at a regulated cost), the BAU case may not be a legally viable option for the DSO in the long run. Nevertheless, the BAU case is used as the counterfactual against which the reinforcement case and the ANM case is compared.

4.1.2. The reinforcement case

In the reinforcement case, the DSO makes an upgrade in the physical network infrastructure. For the sake of illustration, it is here assumed that this reinforcement involves constructing a new medium-voltage overhead line. This investment is expected to require 5 years of permitting and planning, followed by 2 years for construction and testing, which means that it would take 7 years before the capacity of the network has been expanded and the new generation connections can be allowed.

4.1.3. The ANM case

In the ANM case, the DSO implements an ANM solution that enables increased use of the existing network infrastructure. In this illustration, an ANM solution is envisioned where the DSO is given access to control the load and/or generation of a set of flexible resources within the local network area such that the DSO can manage flows on the network. Because of this capability, the DSO is able to connect new customers to the network without making any physical reinforcements.

Compared to the reinforcement case, the ANM solution would be faster to implement. It is assumed to require 2 years for planning and development followed by 1 year for implementation and testing, meaning that new connection can be allowed after 3 years.

4.2. Costs and benefits in illustrative example

This section discusses some costs and benefits that are used to illustrate the CBA framework for the illustrative example. These costs and benefits are here discussed both from a narrow DSO perspective (for the financial CBAs) and from a broader societal perspective (for the economic CBAs).

4.2.1. Investment costs

The investment cost for the new overhead line is the largest cost component for the reinforcement case. These costs include the cost for purchasing the equipment, any costs associated with the construction, installation and testing, as well as the cost incurred during the planning phase.

In addition to the costs directly associated with purchasing and installing the new equipment, the construction of a new overhead line also involves a range of other related costs. The DSO needs to compensate landowners for utilizing their land. Obtaining all necessary permits and approvals is likely to require substantial efforts from DSO personnel, consultancy costs, etc.

For the illustrative example it is assumed that the total investment costs for the reinforcement is 25 million EUR. It is assumed that 5 million of these arise during the planning phase (1 million per year), and 20 million during the 2-year construction phase. The expected useful life of the investment is 50 years, which is assumed to coincide with the regulatory depreciation period. The amount included in the regulatory asset base (before depreciations) is assumed to be the same as the actual investment cost, i.e. 25 million EUR.

The investment costs for the ANM case concerns the development and implementation of ICT infrastructure and systems, but also implementation costs associated with recruiting flexibility providers and personnel training. As noted above, it is assumed that the ANM solution can be implemented faster than the physical reinforcement. It is also assumed that the initial investment cost is lower: 1 million EUR per year during the 2-year planning phase, followed by 2 million EUR for the 1-year implementation and testing phase, for a total cost of 4 million EUR.

The ICT infrastructure and systems are here assumed to have a useful life of 10 years, which again is assumed to coincide with the regulatory depreciation period. A reinvestment is therefore needed every 10 years, at a cost of 2 million EUR. It is assumed that only the implementation costs are eligible for inclusion in the regulatory asset base, meaning that 2 million EUR are included in the asset base (before depreciations) for the ANM ICT infrastructure.

For simplicity, it is here assumed that the societal investment costs (for the economic CBAs) are the same as the financial costs incurred by the DSO for the investments. However, this may not always be the case.

4.2.2. Value of new connections

The main benefit created by the increased capacity of the network (both for the ANM case and for the reinforcement case) is the value that is created by the possibility to connect 30 MW of new wind power generation in the area. For simplicity, it is assumed that both the ANM case and the reinforcement case would be sufficient to enable this.

The new connections would result in additional tariff revenues for the DSO. Specifically, the yearly network tariff payments from the new connections are here assumed be 0.5 million EUR. However, in this illustrative example it is assumed that DSO revenues are determined by a regulated revenue cap, which means that the investment's impact on total tariff revenues need to be considered, not just the tariff revenues from the new connections. This is discussed further in section 4.3.

From an economic CBA perspective, the tariff payments are of less relevance since they do not reflect the underlying economic value created by the new connections. The economic value that is enabled by the new connections is the net economic value created by the wind power investments, i.e. the difference between the value of the energy generated and the costs associated with the investments (including both financial values as well as any externalities). Estimating this value would therefore require an estimate of the expected revenues that the wind power would bring in, the costs for investments and operations, any externalities etc.

Given that investors are willing to invest in wind power in the area, it is reasonable to assume that the economic value created exceeds the tariff payments from the new connections. For this example, the economic value created by the investments is assumed to be 1.5 million EUR per year.

4.2.3. Energy losses

Both the ANM case and the reinforcement case could potentially have an impact on the amount of energy losses that occur in the DSO network, compared to the BAU case. The ANM case involves operating the existing infrastructure closer to its physical limitations. Therefore, it is assumed that the amount of energy losses in the DSO network in the ANM case is higher than in the BAU case.

For the reinforcement case, there are two opposing effects. On the one hand, the additional power flows from the new wind power installations create additional losses in the DSO network compared to the BAU case. On the other hand, the reinforced infrastructure could result in lower losses. For this example, we assume that these two effects cancel out and that the total amount of energy losses in the DSO network are the same under the BAU and the reinforcement cases.

The DSO is responsible for procuring energy to cover the losses that occur in its network. Assuming that externalities in electricity generation are priced appropriately, the financial cost to the DSO (for the financial CBA) and the societal costs (for the economic CBA) attributable to the energy losses are the same. In this example, the additional energy losses in the ANM case compared to the BAU case is assumed to cost 0.1 million EUR per year.

4.2.4. Operational costs

The ANM case and the reinforcement case affect operations and maintenance costs (excluding energy losses) in very different ways. For the reinforcement case, the new overhead line requires some maintenance in the form of, for example, tree clearing. For this example, it is assumed that the reinforcement case therefore leads to an increase in O&M costs of 0.1 million EUR per year, compared to the BAU case.

The operational costs for the ANM case are more complex to represent. The ANM solution requires time from DSO personnel to, for example, monitor the ANM operations and handle the interaction with flexibility providers. Further, the ANM case could involve recurring payments for, for example, software licenses and other IT-related costs. In this example it is assumed that the ANM case would increase DSO costs for this kind of operational items by 0.2 million EUR per year.

The ANM case in this example involves local flexibility providers that sell flexibility services to the DSO. There are two different types of flexibility provision costs of relevance for this example: the cost incurred by flexibility providers for providing the flexibility and the payment that the DSO makes to the flexibility providers for their services. The former is likely to be lower than the later, assuming that the flexibility providers want to earn a profit for providing the services. The cost incurred by flexibility providers include monetary cost as well as their valuation of perceived inconvenience (for example due to variations in indoor temperature or due to a longer duration for electric vehicle charging).

In this example, the flexibility providers' incurred costs for delivering the necessary flexibility services are assumed to total 0.4 million EUR per year, for which the DSO pays 0.5 million EUR per year.

4.2.5. Other externalities

The costs and benefits discussed so far are related to some payment to or from the DSO. However, some costs and benefits have no clear connection to any traded good or service. This type of item may not be relevant for a financial CBA, but they are for economic CBAs. For the illustrative example, the visual impact of the new overhead line in the reinforcement case is used to illustrate a non-traded externality that is included in the economic CBA but not in the financial CBA.

Thus we assume that people living nearby the new overhead line perceive that the overhead line has a negative impact on the beauty of the landscape. Collectively, they would be willing pay 0.2 million EUR per year to not have their landscape affected by the new infrastructure. Even though it is not possible for these local residents to pay that amount and thereby make the overhead line invisible, this negative externality of the new infrastructure should still be included in the economic CBA. This externality is assumed to be present during both the construction phase and when the infrastructure is in place.

4.3. Net present value calculations

Based on the cost and benefit assumptions outlined above, this section calculates net present values (NPV) for the different CBAs and compare the results.

According to the assumptions discussed above, the expected life of the infrastructure associated with the ANM solution (10 years) is shorter than the expected life of the network reinforcement infrastructure (50 years). To provide a fair comparison between the two options, the NPV is here calculated over the same time-period for both cases. The time-period is determined by the longer reinforcement case, with assumed reinvestments every 10 years for the ANM case. The timelines for the NPV calculations are illustrated in Figure 2 below.

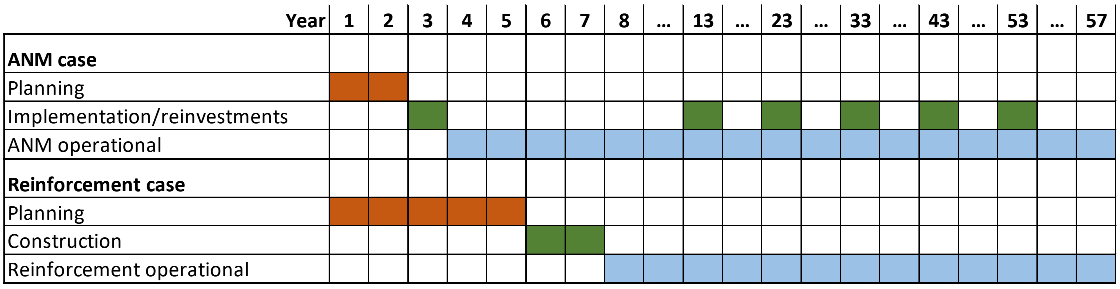

Figure 2 Timeline for NPV calculations

As discussed in section 3.3, the choice of discount rate is a key input for any NPV calculation. For this example, a 5% real discount rate is used both for the financial and economic CBAs. For simplicity, it is also assumed that regulated rate of return used for calculating the revenue cap is 5%.

4.3.1. Representation of the revenue cap

It is here assumed that the DSO is subject to a revenue cap, and that the revenue cap is binding (i.e. the DSO makes full use of the revenue cap). The method used here for calculating the revenue cap is highly simplified and is not meant to mimic the actual revenue cap model of any particular jurisdiction.

The revenue cap is used for calculating the additional tariff revenues that the DSO may collect as a consequence of the investment, compared to the BAU case. There is no need to calculate the total revenue cap amount for the DSO, just the difference in the revenue cap compared to the BAU case.

The revenue cap is here made up of 3 components: operational costs, capital depreciation and return on capital. In this example, it is assumed that all operational costs (O&M costs and energy losses) enters the revenue cap without any modifications, both for the ANM case and the reinforcement case.

Both capital depreciation and return on capital are calculated based on a regulatory asset base. It is assumed that the network reinforcement contributes to the asset base at a valuation of 25 million EUR (i.e. a valuation that equals the actual investment cost, including both planning and construction costs). For the ANM case, the ICT infrastructure is valued at 2 million EUR in the asset base. Therefore, the costs associated with the initial planning for the ANM case are not included in the valuation when determining the asset base. This is the main difference between how the ANM and reinforcement cases are treated by the regulatory model in this example.

For the capital depreciation, linear depreciation is applied from the first year of operation until the end of the expected life of the asset (which here is assumed to be the same as the regulatory depreciation period of the asset). For the reinforcement case, this means that 0.5 million EUR (25/50) enters the revenue cap every year during the operational phase. For the ANM case, capital depreciations are 0.2 million per year (2/10) during the operational phase.

The regulatory rate of return is here assumed to be the same as the DSO's required rate of return, i.e. 5%. The return on capital is therefore 5% of the asset base, where the asset base in a given year during the operational phase is obtained by subtracting the depreciations made in previous years from the initial asset base amount.

To summarize, the change in revenue cap for operational year $i \in \{1, \ldots, T\}$ is given by:

$$\Delta \text{ revenue cap} = \text{OPEX} + \frac{\text{A}}{T} + 0.05 * \left(A - (i-1) * \frac{A}{T}\right)$$

where T is the depreciation period in years, and A is the valuation of the investment in the asset base. The yearly depreciation amount is therefore A/T and the asset base in year i is given by $\left(A - (i-1) * \frac{A}{T}\right)$.

4.3.2. Financial CBA

This section presents the results from the financial CBAs. Table 1 provides summary information for the reinforcement case. The three rightmost columns summarize the cost and benefits that make up the input data for the NPV calculation, and the column highlighted in blue shows the resulting net present value for each category. Negative values reflect costs and positive values reflect benefits. For example, the investment costs (1 million per year during the planning phase and 10 million per year during the construction phase) correspond to an NPV of 18.9 million EUR.

Table 1 Financial CBA summary for reinforcement case

Financial CBA summary Reinforcement case	NPV	Planning phase Years 1-5	Construction phase Years 6-7	Operational phase Years 8-57
Investment costs	-18.9	-1 per year	-10 per year	
Energy losses	0.0			No net impcat
O&M costs	-1.3			-0.1 per year
Tariff revenues	19.1			Differs by year
Total net benefit	-1.1			

All values in million EUR

The tariff payments made by the newly connected customers are assumed to be 0.5 million EUR per year. However, this amount is not what determines the total impact that the investment has on DSO revenues. Instead, the investment influences the calculation of a revenue cap, which in turn governs the DSO's revenues. Therefore, the amount listed for "Tariff revenues" in Table 1 is not based on the payments made by the newly connected customers, but rather based on the increase in the revenue cap. See section 4.3.1 above for details concerning the calculation of this amount.

In this example, the increase in total tariff revenues turn out to be greater than the payments made by the newly connected customers (0.5 million EUR per year during the operational phase of the reinforcement case corresponds to an NPV of about 6.5 million EUR). This is however highly dependent on the specifics of the case and the details of the regulatory model.

The total net benefit when combining all NPVs in this example is negative 1.1 million EUR. In other words, the financial return for the DSO on this investment does not quite reach the 5% required return on investment. Instead, the IRR for the investment becomes about 4.5%.

Since the regulated rate of return and the discount rate used for the NPV calculation (i.e. the DSO's required rate of return) are both equal to 5%, and since all cost components are included in the revenue cap calculation, one might expect that the NPV should be 0 by construction. The reason why the NPV instead becomes slightly negative is that the investment costs are spread out over the planning and construction phases but are not included in the asset base (and hence does not create any revenues for the DSO) until the project is completed and operational. Had the full investment cost occurred in year 7, then the NPV would have been exactly 0 in this example.

Table 2 provides the same information as Table 1, but for the ANM case. Despite the much lower investment costs, the total net benefit for the DSO is in this example even more negative (-1.9 million EUR) and the IRR is close to zero. In this example, this is primarily driven by the difference in how the regulatory model accounts for planning costs in the ANM case versus the reinforcement case. In the reinforcement case, the planning-related investment costs are included in the asset base, while this in not true for the ANM case. Of course, this does not need to be the case in practice.

The point here is to illustrate that a seemingly small difference in the regulatory model can affect the relative ranking of the investment options.

Table 2 Financial CBA summary for ANM case

Financial CBA summary ANM case	NPV	Planning phase Years 1-2	Implementation Year 3	Operational phase Years 4-57
Investment costs	-6.1	-1 per year	-2	-2 every 10 years
Energy losses	-1.6			-0.1 per year
O&M costs	-11.2			-0.7 per year
Tariff revenues	17.0			Differs by year
Total net benefit	-1.9			

All values in million EUR

Since both the reinforcement case and the ANM case show negative total net benefits, the profit-maximizing choice for the DSO in this example would be the BAU case. If this is not a viable option, then the reinforcement case would be the lower cost alternative for the DSO in this example. This result is to a large extent driven by the assumed regulatory model.

4.3.3. Economic CBA

This section presents the economic CBA results. Since economic CBAs are performed from a societal perspective, the underlying value of the new connections is included instead of the tariff revenues. This means that the regulatory model does not enter the economic CBA calculations. Further, the visual impact of the new overhead line is included as an example of a non-traded externality.

Table 3 shows a summary of the economic CBA for the reinforcement case, showing that the net present value is negative (the IRR is just below 4%). However, as seen in Table 4, the ANM case has a large positive net present value (corresponding to an IRR of about 15%). Therefore, the ANM solution has a much higher economic value than the traditional network reinforcement.

Table 3 Economic CBA summary for reinforcement case

Economic CBA summary Reinforcement case	NPV	Planning phase Years 1-5	Construction phase Years 6-7	Operational phase Years 8-57
Investment costs	-18.9	-1 per year	-10 per year	
Value of connections	19.5			1.5 per year
Energy losses	0.0			No net impcat
O&M costs	-1.3			-0.1 per year
Visual impact	-2.9		-0.2 per year	-0.2 per year
Total net benefit	-3.6			

All values in million EUR

Table 4 Economic CBA summary for ANM case

Economic CBA summary ANM case	NPV	Planning phase Years 1-2	Implementation Year 3	Operational phase Years 4-57
Investment costs	-6.1	-1 per year	-2	-2 every 10 years
Value of connections	24.1			1.5 per year
Energy losses	-1.6			-0.1 per year
O&M costs	-9.6			-0.6 per year
Visual impact	0.0			no impact
Total net benefit	6.7			

All values in million EUR

4.3.4. Discussion

In this illustrative example, the economic CBA shows that the ANM case has a much higher value than the reinforcement case from a societal perspective. If the BAU case is not a viable option, then the economic value created by the ANM solution is over 10 million EUR compared to the reinforcement case (a net benefit of 6.7 million EUR instead of a net cost of 3.6 million EUR).

However, even though the AMN case has a higher economic value, the financial CBA shows that the ANM case is not the most financially attractive for the DSO. According to the financial CBA, neither of the cases meet the DSO's required return on investment, but the reinforcement case gets closer. Therefore, the ANM case does not create a financial value for the DSO in this example. The financial CBA also shows how important the details of the regulatory model is for the outcome. A change in the regulatory model alters the amount of additional tariff revenues the DSO is allowed to collect in the different cases and can therefore significantly change the attractiveness of the ANM case from a financial perspective.

This illustration shows that the "value of ANM" from a planning perspective can look very different depending on whether the analysis is made from a financial DSO perspective or from a broader economic perspective. It is possible for the ANM case to have a high value from one perspective, while not being valuable at all from the other.

The analysis presented in this example could easily be extended to include additional investment options, for example where an ANM solution is combined with minor reinforcements, or where the ANM solution is used for postponing a network reinforcement rather than replacing it. The latter could be especially valuable from a financial DSO perspective if the reinforcement replaces an existing asset, which has not been fully depreciated.

Finally, as noted in section 3.4, if this was an actual application of the CBA framework on a real case, it would be necessary to complement the analysis with sensitivity analysis and/or Monte Carlo simulations to capture the large amount of uncertainty that would likely be associated with several of the estimated costs and benefits. For example, some investment option may be better suited for accommodating future unforeseen developments, such as further load or generation growth in the area.

5. VALUE OF ANM FROM A SHORT-TERM PERSPECTIVE

The discussions so far in this chapter have been focusing on the value of ANM from a long-term planning perspective. While this is the appropriate perspective when determining whether an ANM solution should be invested in or not, it is also interesting to consider how this relates to the short-term perspective and the value of flexibility services in short run.

When discussing the short-term value of a flexibility service, it is important to differentiate between the following three items:

1. The cost incurred by the flexibility provider for delivering the flexibility service.
2. The payment that the DSO makes to the flexibility provider for providing the flexibility service.
3. The amount that the DSO is at most willing to pay for the flexibility service.

For the ANM solution to be valuable to both the DSO and the flexibility provider, the payment that the DSO makes (item 2) should be higher than the cost for delivering the service (item 1) and lower than the DSO's willingness-to-pay (item 3). The long-run value of ANM from a planning perspective is related to the latter, as discussed below.

5.1. From long-run to short-run valuation

The financial CBA method described in this report could be used to estimate the maximum amount that the DSO can pay for flexibility services before the ANM solution becomes less financially attractive then a network reinforcement. This can yield an annual average cost of flexibility services that the DSO would find financially acceptable in the long run. Based on an assessment of the amount and frequency of flexibility activations that are likely to be needed, this amount can be further broken down to an average long-run willingness-to-pay for flexibility activations. Such a value can serve as a benchmark for what the DSO at most would be willing to pay for flexibility services, i.e. item number 3 above.

From a regulatory perspective, the regulator must decide to what extent payments for flexibility services should be included when calculating the revenue cap. For this purpose, an economic CBA could be used for estimating if the use of an ANM solution is motivated from a societal perspective, and hence whether the costs associated with procuring flexibility services can be viewed as being prudently incurred.

5.2. Maximum willingness-to-pay and the holdup problem

When using a long-run CBA approach to estimate the DSO's willingness-to-pay for flexibility services, a long-run average willingness-to-pay is obtained. However, once the DSO has decided to implement an ANM solution, and therefore rely on it for day-to-day grid operations, the short-run willingness-to-pay for a particular flexibility activation is potentially much higher.

This can be viewed as a version of the *hold-up problem*, a suboptimality that may arise when contracting is incomplete [20]. Once the DSO has decided to rely on a flexibility provider for flexibility services, that flexibility provider may be in a very strong negotiating position in the short run. In the long run, the DSO may have other reasonable options (such as a network reinforcement), but in the short run the DSO relies on the flexibility provider for maintaining safe and reliable grid operations, and may therefore be willing to pay a very large amount for the flexibility services.

If the DSO recognizes that this situation may arise, it will likely hesitate to enter into such an agreement with a flexibility provider in the first place. Potential solutions to this issue could involve the DSO and the flexibility provider entering into (relatively detailed) long-term contracts that require the flexibility provider to provide certain services at a certain price. Another possible solution would be to ensure that sufficiently many flexibility providers are available in any given situation, and then rely on competition between the flexibility providers to keep flexibility service prices from soaring.

5.3. Other sources of value

In addition to providing a substitute to traditional network reinforcements, ANM solutions could potentially create value to the DSO in other ways. Such alternative sources of value could motivate an ANM solution in their own right or could provide some additional values on top of the value created by replacing the need for traditional reinforcements.

One type of value arises if the DSO has a contract with the overlaying network owner (such as a TSO) where the DSO needs to pay a penalty fee if the DSO’s total load exceeds a certain amount. When this is the case, the DSO could use the ability to activate flexibility resources to manage the peak load of the DSO as a whole.

CHAPTER 2: ANM CONTROL ALGORITHM FOR ACTIVE & REACTIVE POWER

(ANM4L DELIVERABLE D3.1)

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1 PURPOSE OF ANM ALGORITHMS

Present distribution networks are generally designed to supply consumers with electricity. The Active Network Management control algorithms in this work are developed with the aim to manage two fundamental issues related to the growing presence of renewable energy sources in radial distribution networks, namely excessive voltage levels and excessive current usually called congestion. To ensure operation within network limits for voltage and current, the algorithms rely on flexibility resources which allows for control of both active (P) and reactive (Q) power. Details and characteristics of such resources are treated in Chapter 3.

1.1 Voltage and current limits

Voltages in electricity networks change more or less with variations in generation and consumption. In public distribution systems in Europe, the standard EN 50160 formulates requirements on the voltage supplied to customers at LV (Low Voltage <1000 V) and MV (Medium Voltage 1-35 kV) level. For slow variations captured by 10 min averages, the deviations from the nominal value should be within ± 10 % for 95 % of a week. This serves as a minimum requirement, and many distribution system operators (DSOs) aim at keeping the voltage magnitude within a narrower range.

Current in all sorts of electric equipment contribute to heating of the equipment through Joule losses. It is obvious that excessive currents cause immediate damage while low currents have no impact at all. Between these extremes, long term exposure to high currents causes aging of insulation material and reduces the lifetime of the equipment. For all equipment, manufacturers define a rated current, which is the maximum current that can be allowed continuously while maintaining normal lifetime. For cables, the heating is the main concern, but for overhead lines the elongation caused by the heating is more important as insufficient clearance below a line is a matter of electrical safety. For transformers, the rating is normally expressed in MVA; which is a product of rated current and voltage.

1.2 Controllable resources

Both active and reactive power contribute to voltage deviations and they both contribute to congestion. This means that to mitigate these problems it is of interest to control both active and reactive power. The extent to which this is practical differs between different devices and in this work the following assumptions are made:

Photovoltaic (PV) units always use an inverter to inject active power into the grid. Using an external signal, this active power can be reduced – at most down to zero. The reactive power is specified by the grid code but is considered available for control. While the control of active and reactive power is independent, the active and reactive current components are parts of the total current, which is limited by the current rating of the inverter. Both active and reactive power are considered continuously variable; no discrete values are considered.

Wind turbine generators today use an inverter-based grid interface like the PV units. In terms of control, they are treated in the same way.

Consumption mainly draws active power but may also draw an associated amount of reactive power. In this work, only the active power is assumed continuously controllable.

Battery energy storage are inverter-based and can be considered a variation of PV, with variable reactive power but with the difference that active power can be reversed.

2 ANM ALGORITHM FOR VOLTAGE LIMITATION

Even though the ANM algorithms for voltage limitation and congestion management are similar, the two issues are different, and they are here treated separately. This chapter explains the issue of overvoltage, discusses control strategy aspects that have been considered and describes three versions of the voltage limitation algorithm. In the first version reactive power is controlled using feedback, in the second using constant power factor and in the third it is excluded.

2.1 Voltage Changes in Distribution Networks

Traditionally, distribution networks are built to maintain sufficiently high voltage at maximum load. In this case, voltage is highest at the feeding transformer and decreases along the feeder. For a single load drawing active power P and reactive power Q at the end of the feeder, the <u>decrease</u> ΔV is approximately:

$$\Delta V \approx \frac{RP}{V} + \frac{XQ}{V},$$

where R and X are series resistance and reactance respectively of the line between transformer and feeder end. The same expression applies in the opposite case with a single generating unit at the feeder end, injecting P and Q. Here ΔV is an <u>increase</u> in voltage, see Figure 3.

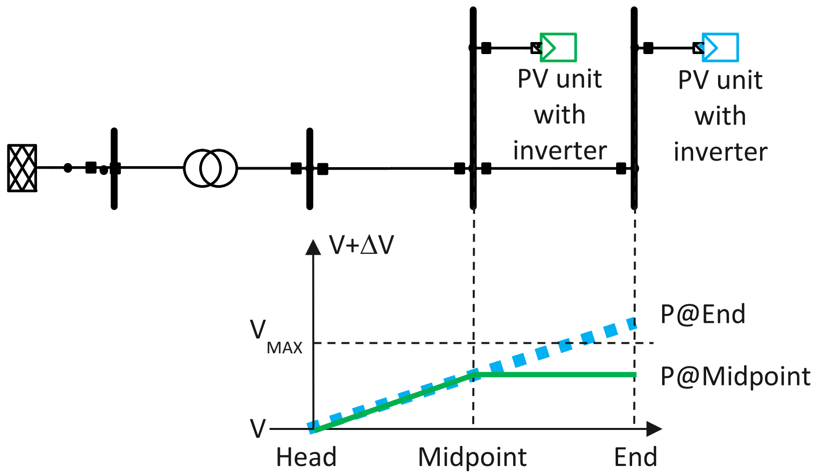

Figure 3. In an unloaded radial distribution feeder, adding generation of active power P raises the voltage by ΔV. Here P is added at the midpoint (green) or at the end of the feeder (blue). Consumption can be considered as negative generation.

Intermediate points on the feeder have R and X in proportion to the distance from the feeder head. At the midpoint of the feeder, R and X thus take half the end point values. In other words, the voltage rise at the midpoint caused by e.g. a certain PV generation P is only half what the same P would cause at the feeder end, see green and blue cases in Figure 3. The same expression for ΔV applies for countermeasures in terms of active and reactive power P and Q. These also have more impact the greater R and X are. To summarize, high voltage is most likely to happen at the end of the feeder, and this is also where countermeasures are most effective.

To reduce the voltage at the end of the feeder the flow of active power towards the transformer can be reduced. It can be done by reducing the net P injected by either curtailing renewable energy sources or by increasing power consumption and battery charging rates. An alternative to adjusting active power towards the transformer is to increase the reactive power absorption at the feeder end, which is straightforward with connected converter-interfaced generation units.

As can be deduced from the equation above, the efficacy of each method is determined by the X/R ratio of the line impedance: Relatively large resistance R favours active power control while large reactance X suggests the use of reactive power control. For a given voltage level, the X/R ratio is determined by the line or cable type and cross-section area. European distribution networks exhibit large variations in X/R ratios, ranging from 0.1-1.4 in low voltage (0.4 kV) networks to 0.5-2.5 in medium voltage (20 kV) networks [21].

The choice of control method is also a matter of costs. While curtailment of renewable energy sources in many cases is effective to mitigate overvoltage, it is also associated with some loss in revenue for the producer. It might be preferable to instead utilise reactive power to a larger extent, as its use is not related to any significant costs, see details in Chapter 3. At the same time, the availability of reactive power is largely restricted by the active power production which means achieving large P production and large Q consumption simultaneously gives a high inverter current. It is therefore possible only through oversizing the converter, normally a costly investment. An alternative way to reduce the feeder voltage level without curtailing renewable power production is to increase the consumption of active power using flexible loads or initiating charging of battery energy storage devices. While transformer tap changers are the most important means to adjust voltage today, their control mainly focuses on avoiding undervoltage. This is left unaffected and tap changers are excluded in this report.

2.2 Control Strategies

A wide range of voltage limitation control strategies involving active and/or reactive power have been proposed in literature (some examples can be found in [22], [23], [24]). Other key aspects that are typically considered are:

- Level of coordination and communication between controlled flexibility resources,
- availability of real-time measurements or reliance on state estimation, and
- complexity of network integration and implementation.

As explained, the voltage problem is local in the sense that where voltage deviates most, is also where a change of power gives the largest voltage change. Purely local control strategies are thus an attractive and straight-forward approach, which also allows for simple and cost-effective "plug-and-play" implementation. The drawback is that the lack of coordination – through real-time communication or manual parameter adjustments – makes any optimization of control actions unrealistic and consequently the use of available resources becomes less efficient.

While optimization techniques can be used to maximize grid utilisation, these practically imply communication and coordination between assets. The added operation complexity for the implementation of an optimal control scheme raises the threshold for when such a solution can be financially and technologically motivated. In practice, integration of renewable energy sources is a continuous process. When penetration of wind power or solar electricity reach high levels, the usual margins in grid capacity motivated by uncertainty in power flows cannot be upheld anymore. The major contribution from ANM is then to first extend the range of safe operation – effectively exploiting the margins by permitting larger power flows. The shift from <u>requiring</u> margins to safely <u>using</u> the margins can best be started with a simple solution that focuses on not exceeding limits.

Another reason for starting simple is that the development of RES technology is impacted by several factors outside the control of distribution system operators, complicating forecasting of future voltage flexibility needs. Local "plug-and-play" solutions have the advantage that they can develop together with new distributed generator units. This view is reflected by the popularity of local droop-like Volt-Var or Volt-Watt control schemes in various grid codes [25], [26].

The development of the voltage limitation algorithms in the ANM4L project has been carried out with the intention that the control schemes should be:

- easily deployable,
- scalable, and
- adaptable to different network topologies.

Thus, local solutions have been favoured. Another important objective has been to go beyond static Volt-Var or Volt-Watt schemes to improve utilisation of flexibility resources. The development approach can be summarised by four core principles, namely

- Local control with local voltage measurements.
- Increasing grid utilisation through safe operation up to voltage limits.
- At any time, use engage the flexibility resources that offer the most effectiveness at least cost. Typically reactive power as the first control action, and curtailment of generation or increase of active power consumption when reactive power is insufficient.

2.3 ANM Voltage Limitation Algorithm for Renewable Energy Sources

The algorithms for local voltage limitation control are well suited for implementation in RES inverter control software. This would yield a plug-and-play solution that makes it impossible to exceed the maximum voltage limit. This could be specified by a connection requirement, just like existing local solutions like fixed power factor or the Volt-Var or Volt-Watt control schemes mentioned above.

The ANM voltage limitation algorithm is based on a PI controller, see Figure 4, for each individual resource. While PI controllers traditionally act to bring the measured quantity to a reference value, the controller here only acts when the measured quantity is above the reference value.

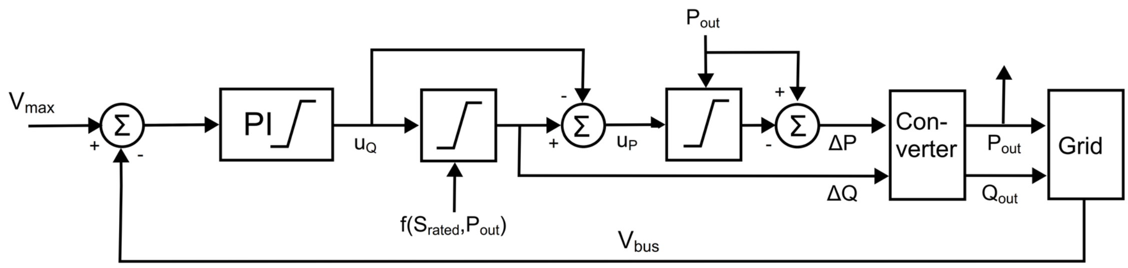

Figure 4. Q+P local voltage limitation control block diagram.

This is achieved by the asymmetric output limits Q_{min}=–Q_{max} and 0 of the PI controller that permits the controller to only reduce voltage. This is done by ordering the generator to to draw reactive power from the grid. If –Q_{max} is reached without voltage being returned below V_{max}, the controller starts to curtail the generation by reducing the active generation by ΔP. The converter current is limited to the rated current, corresponding to the MVA rating S_{rated}, of the converter. Due to the higher value of active power, it is given priority over reactive power that is limited by the remaining capacity.

The above algorithm remains passive until the voltage is above V_{max}. In networks where the algorithm is used in several units along a feeder, this is an advantage as long as voltage is acceptable everywhere and as long as the reactive power does not saturate anywhere. But when reactive power capability saturates at one point, curtailment starts there before all other reactive power resources have been depleted which is undesirable.

A better strategy draws reactive power before the voltage limit has been reached. One option for this is to draw reactive power in proportion to the generated active power, yielding constant power factor $\cos\varphi$. This makes great sense as selecting the power factor that gives Q/P = –R/X cancels the voltage rise completely, see the expression for ΔV above. But as R is usually greater than X in LV networks, it means that more reactive power should be drawn than active power should be delivered. This implies a very large converter and also requires knowledge of R and X. A reasonable choice is a more modest Q/P=0.5 corresponding to a power factor of 0.9.

The voltage limitation algorithm using constant power factor is seen in Figure 5. In this case reactive power is drawn in proportion to active power and when voltage reaches V_{max} it starts curtailing active power. This gives more room for active power and the power factor could go even lower, but this is not implemented yet.

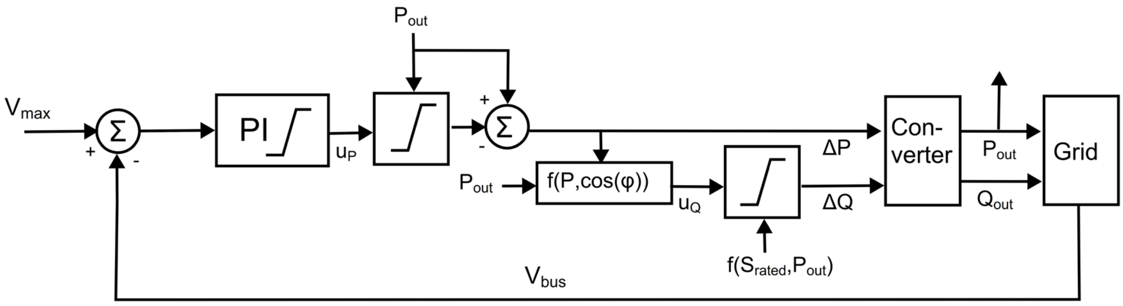

Figure 5. Constant power factor local voltage limitation control block diagram

2.4 ANM Voltage Limitation Algorithm for Loads

If only active power can be controlled, the scheme is simplified, see Figure 6. Note that generation and consumption have opposite effect on voltage, so in case of overvoltage the algorithm will increase load.

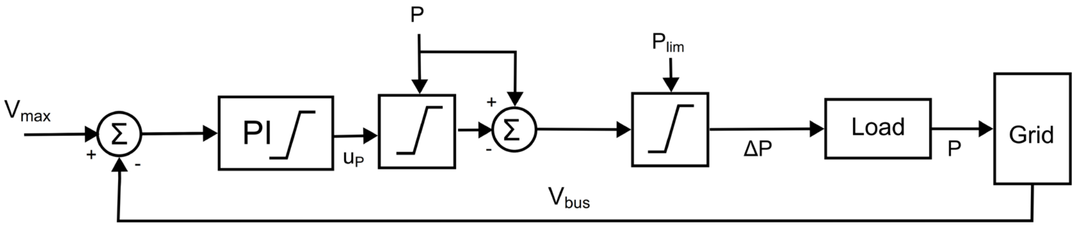

Figure 6. Active power load local voltage limitation control block diagram

3 ANM ALGORITHM FOR CONGESTION MANAGEMENT

This chapter explains the issue of congestion management, discusses control strategy aspects which have been considered and describes the congestion managements algorithm. This algorithm can easily be modified to control of reactive power to limit only reactive power flow, which is also described.

3.1 Congestion in distribution networks

Congestion in distribution networks occur when too much power or – equivalently – current is sent through a transformer or line, see Figure 7. The transformer or line is then overloaded leading to excessive heating and in the case of overhead lines to insufficient clearance between line and ground. The rated line currents and transformer MVA ratings are usually selected to provide margin to maximum consumption, but the network situation regarding consumption and production may change considerably during their lifetime. An important issue in deciding maximum consumption is if the peak of individual consumers coincide and yield a relatively high total peak demand, or if they exhibit diversity leading to lower total peak demand. Generation behaves very differently, and PV within a local area mainly deliver their peak generation at the same time.

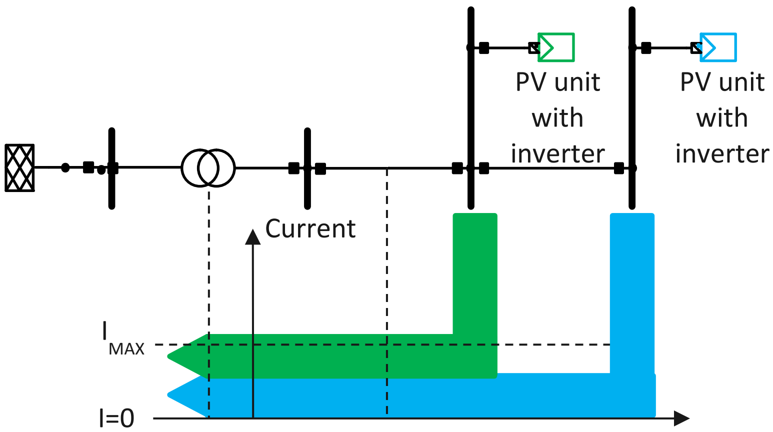

Figure 7. In an unloaded radial distribution feeder, adding generation of active power P raises the transformer loading, here leading to congestion or overload at the dashed line (at transformer or line). The transformer and line loading rises practically regardless of the location of the generation. Consumption can be considered as negative generation.

If the transformer in Figure 7 is congested, the countermeasure is to reduce the flow of active or reactive power through the transformer. This can be done at other nodes, which requires communication of some sort between point of measurement and point(s) of control. Local control is not possible as is the case for voltage management.

If network losses are disregarded the transformer load is simply the sum of all consumption and generation connected to the secondary side feeders. This means that the contribution from the individual nodes does not depend on where on the feeder they are located. The same applies to where control actions are taken – this can be anywhere on the feeder. The line parameters R and X determine if the network losses can actually be disregarded.

If network losses cannot be neglected, location does matter. The nodes can then be ranked based on a sensitivity that is implicitly used in power flow calculations. The branch sensitivity or Power Transfer Distribution Factor $PTDF_{ij}$ relates the change in generation or consumption at node i to the change in power flow through branch j:

$$PTDF_{ij} = \frac{\Delta S_{branch-j}}{\Delta S_{node-i}}$$

Calculation of the branch sensitivity requires all line parameters such as R and X.

3.2 Control Strategies

A control strategy for congestion management cannot be local like for voltage management. Apart from that, the choice control strategy must consider the same aspects:

- Level of coordination and communication between controlled network resources,
- availability of real-time measurements or reliance on state estimation, and
- complexity of network integration and implementation.

Again the main trade-off is roughly speaking between optimality and simplicity, which in this case means easily deployable, scalable and adaptable to different networks. For congestion management, the core principles are three:

- Increasing grid utilisation through safe operation up to current limits.
- At any time, engage the flexibility resources that offer the most effectiveness at least cost. Typically use reactive power first if relevant, then increase active power consumption and finally curtail active generation.

3.3 ANM Algorithm for Congestion Management

The ANM congestion management algorithm is based on a PI controller, see Figure 8. It has two similarities with the ANM voltage limitation algorithm:

1. It assumes excessive generation on the feeder, and
2. it acts first when the monitored quantity has exceded its maximum value.

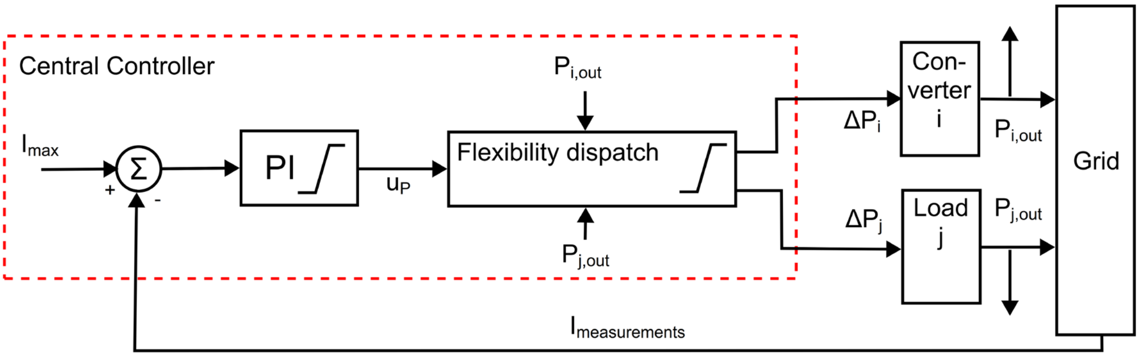

Figure 8. Block diagram of central control of active power consumption and generation for congestion management. Flexibility dispatch decides in which order flexible resources should be used.

The PI controller has asymmetric output limits $-P_{max}$ and 0. When $I_{measurements}$ exceeds I_{max} the controller asks for either load increase or generation curtailment. The selected control action is determined by the flexibility dispatch. This can be seen as an ordered dispatch list, where the flexibility of each resource is used completely before the next is used. The list can be ordered in many ways, but three options are particularly relevant:

- Order dispatch list by monetary cost for certain volume such as 1 kWh, see Chapter 3. If two resources have the same cost, they are used simultaneously.
- Order dispatch list by technical efficiency of the resources using branch sensitivities. Cost and efficiency can also be combined.
- Order dispatch list by a combination of monetary cost and technical efficiency, yielding monetary cost for certain technical impact.

As the PI controller raises the control effort, the flexibility dispatch thus allocates the flexibility resources that are most efficient – in terms of cost, impact or a combination. This is very similar to the price curve use for marginal pricing, which for any required volume allocates the generation that has the least cost

3.4 ANM Algorithm for Reactive Power Management

Congestion management is a matter of limiting a flow. This limit can actually be zero, which is relevant for exchange or reactive power across a TSO/DSO interface. An ANM algorithm for such reactive power management results from changing active power to reactive power in the congestion management algorithm, see Figure 9.

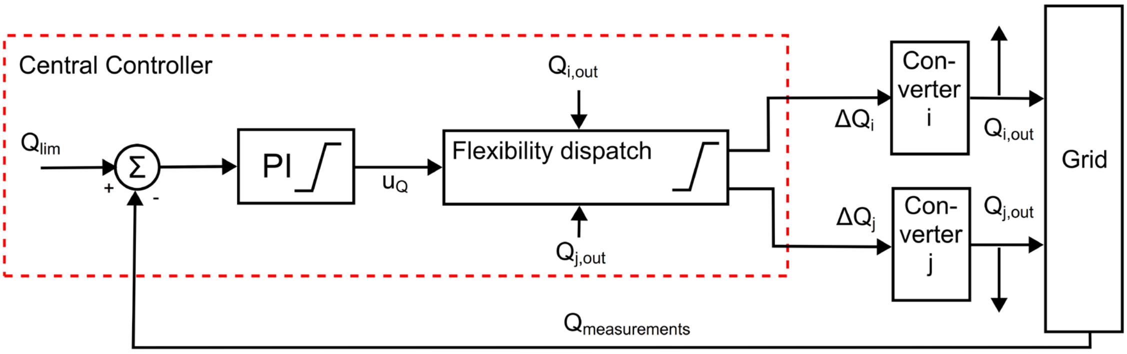

Figure 9. Block diagram of central control of converters for reactive power management. Flexibility dispatch decides in which order flexible resources should be used.

The idea is that the reactive power capability of e.g. wind turbine generators replaces installation of reactive power resources such as shunt capacitors or shunt reactors. The flexibility dispatch is carried out like for the congestion management case.

4 ALGORITHM SIMULATION AND TESTING

The developed algorithms are intended for use in distribution networks, regardless of voltage level or the rated power of flexibility resources. In this section, a medium voltage test network with wind power generation is used to demonstrate the functionality of the algorithms described in Sections 0 and 0. The developed methodology is equally valid in other configurations, such as for a low voltage network with PV units.

4.1 Test System

The algorithms have been tested with the *CIGRE* benchmark MV network [21]. The 20 kV network consists of two feeders, each connected to an overlying 110 kV network through a 25 MVA transformer. There are 14 MV buses in total, with 13 of them being load buses. To demonstrate the performance of the ANM algorithms, the smaller benchmark feeder was modified to include distributed generation in form of two small wind power plants. The updated feeder is shown in Figure 10.

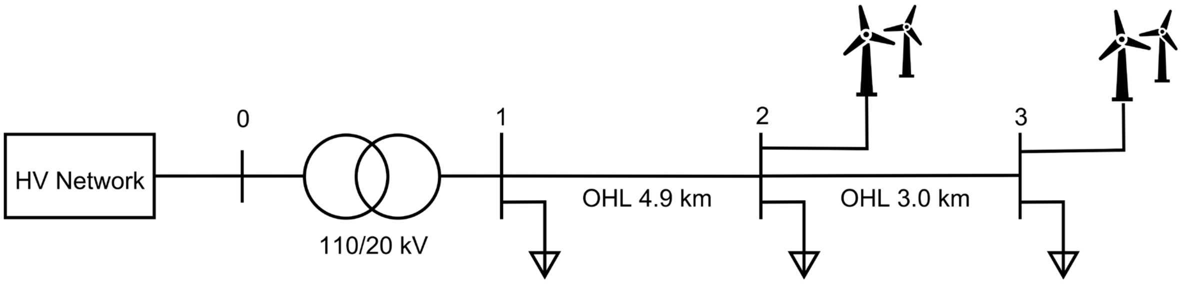

Figure 10. Modified feeder in CIGRE MV benchmark network with wind farms at buses 2 and 3.

The loads at buses 1-3 represent a combination of aggregated residential, commercial, and industrial loads. The load at bus 1 is close to 40 times greater than the combined loads of buses 2 and 3, as it represents aggregated loads from parallel feeders not explicitly modelled in the benchmark network. The benchmark daily load profiles have 15 min resolution and are shown in Figure 11. The corresponding daily generation profile for the wind farms is shown in Figure 12.

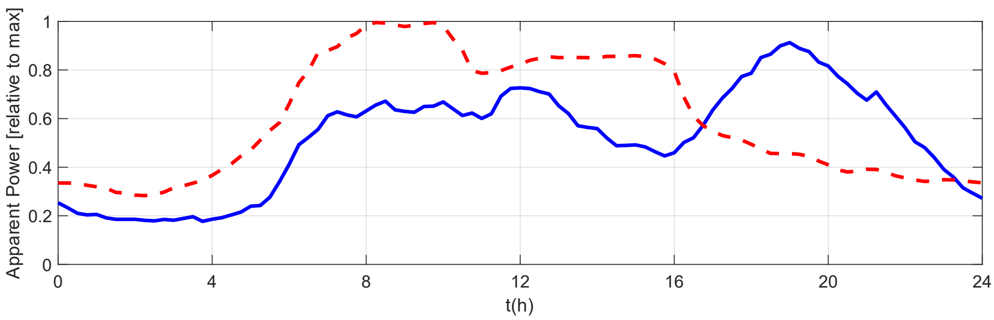

Figure 11. Daily load profiles. Residential load in blue, and industrial/commercial load in dotted red.

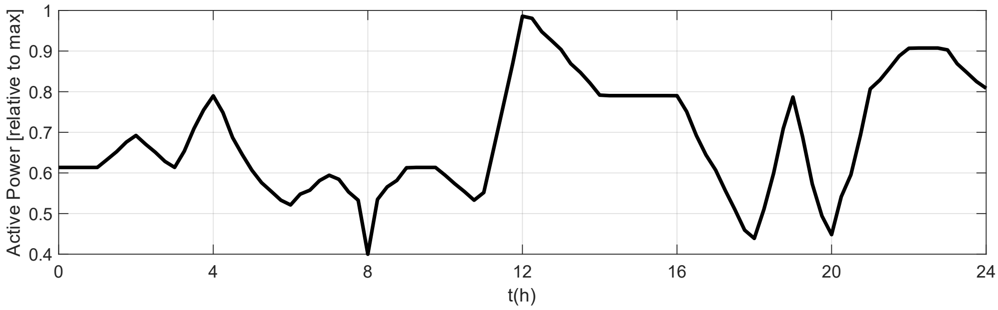

Figure 12. Daily wind generation profile.

The MV buses are connected through long overhead lines (OHLs), mimicking the characteristics of a rural network. The total rated generation capacity is 9 MW, and the ratio between generator rating and maximum load is roughly 75:1 at bus 2 and 10:1 at bus 3. This means the voltage profile is highly dependent on the wind generation pattern. The ANM algorithm performance was therefore specifically tested in simulations with the daily profile at midday, where the wind generation is close to 100 % of the rated active power, creating a need for control actions. It is assumed, based on European grid codes that the wind power converters can provide a power factor, cos(φ), ≤ 0.95 leading/lagging at full power production [25].

At 12:00, 3 MW of wind power is generated at bus 2, while at bus 3 the wind power plant injects 6 MW. This results in overvoltage and the end of the feeder, as well as overloading of the line between buses 1 and 2. In the following sections, the two problems will be treated separately, and the related reactive power management algorithm will then be discussed.

4.2 Simulation Environment

The modified *CIGRE* benchmark network was implemented in *DIgSILENT PowerFactory*, while the ANM algorithms were stored in separate *Python* scripts. The algorithms were deployed for use in balanced three-phase networks. To accommodate time-series input data of different resolutions, a linear interpolation method was also implemented. The relative generation profile was then applied to the added wind power plants. All simulations were based on iterative power flow calculations with stepwise data exchange between the simulation software and the active ANM algorithm. Important parameters in this aspect are the sampling interval and the rate of change of active and reactive power output. They should be selected such that sufficient control performance can be achieved while a time-scale separation to inverter dynamics is maintained. The sampling interval in the following example was set to 10 seconds, and it was assumed that steady state is achieved after a set point change well within that time frame for all participating flexibility resources. The maximum rate of change in this case was set to +/- 10 % per 10 seconds time step.

4.3 ANM Voltage Limitation Algorithm Performance

Given the ratio between the present generation and demand in the benchmark feeder, it is natural to first look at controlling the wind power plants for voltage limitation purposes. The upper voltage limit was set to 1.05 p.u. and the ANM algorithms described in section 2.3 were used in simulations of a high-production mid-day scenario at 12:00. Two different constant power factors were used to visualise the interaction between changes in reactive power and curtailment. The resulting feeder voltage profiles are shown in Figure 13. It is evident that all algorithm variants can limit the voltage at the end of the feeder. The voltage at the beginning of the feeder is also lowered in all cases. Particularly when a generous power factor is used special attention must be paid to this issue to avoid undervoltage problems at parallel feeders without generation.

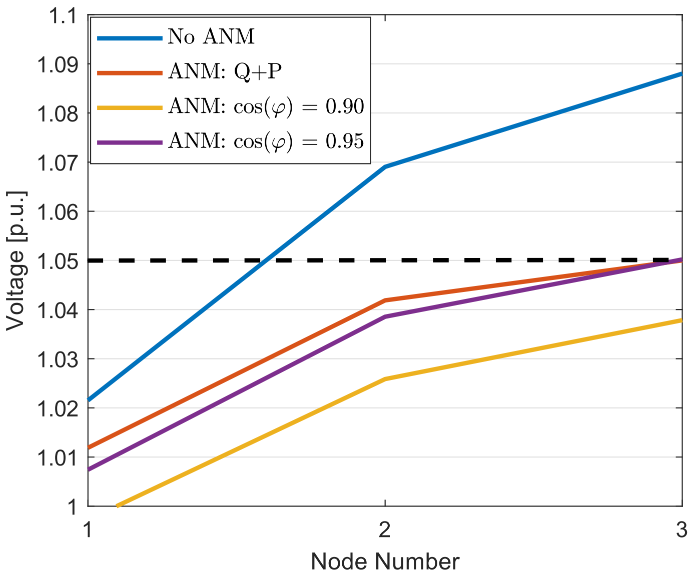

Figure 13. CIGRE MV feeder voltage profile at 12:00. Maximum allowed grid voltage is 1.05 p.u. (dotted black line)

Figure 14 shows the total generated power for the different cases. The output from the wind power plant at bus 2 is unaffected by any action by the ANM algorithms, as the steady state voltage at bus 2 is below the limit. The sequential Q+P algorithm is assumed to be used with inverters that provide a power factor 0.90 at rated active power, and the algorithm was allowed to freely change power factor to maximise the inverter reactive power capabilities when the active power output was lower than the rated power. As seen in Figure 14, neither the Q+P algorithm, nor the constant power factor algorithm, in the case when the power factor is set to 0.90, affect the active power injections at bus 3. When the constant power factor 0.95 is used, curtailment is needed to reduce the voltage. This results in a reduction of the power at bus with roughly a sixth of the potential output.

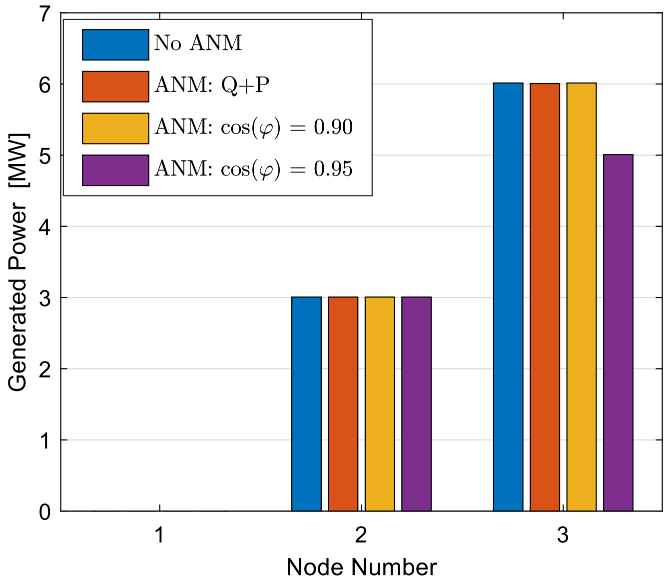

Figure 14. Generated power from wind turbine generators in the simulated benchmark system at 12:00.

From Figure 15 a major difference between the sequential ANM algorithm and the constant power factor algorithms can be distinguished. The Q+P algorithm allows for changes in reactive power only when the voltage limit is violated, which leads to a stronger reaction at bus 3. Eventually it leads to a steady state where reactive power is only absorbed at the end of the feeder. The resulting power factor is slightly smaller than 0.90 since the active power output is just below the rated power at midday in the studied scenario.

With a constant power factor reactive power is instead absorbed at both bus 2 and 3. Given a sufficiently generous power factor no curtailment is necessary, as seen when cos(φ) = 0.90. However, with a smaller amount of reactive power available, curtailment is still needed to limit the voltage.

A significant amount of reactive power is absorbed when the power factor is 0.90. When compared to the sequential algorithm simulation, the difference in active power output is relatively small compared to the reactive power changes. This shows the impact of the X/R ratio on P and Q efficacy and the dependence of voltage change sensitivity on the location of change of P or Q. One can conclude that given large converter and power transfer capacity margins, an ANM algorithm relying on a constant power factor with gradual curtailment as a secondary control action, would provide means to allow a large share of distributed generation, while maintaining high network utilisation. However, increasing network complexity and stricter operational constraints would require a smaller and more efficient use of reactive power resources. Given that the sequential Q+P algorithm does not increase reactive power consumption during normal operation, and when a constraint violation occurs changes reactive power set points only at affected locations, it might then be preferrable to use.

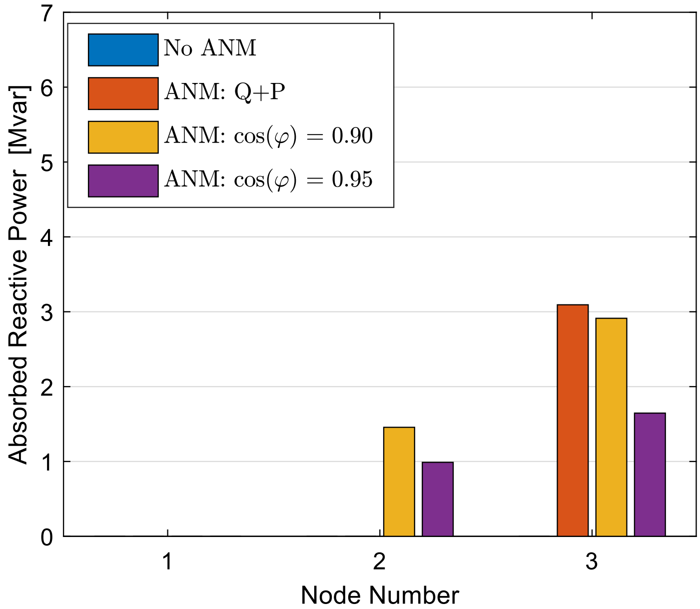

Figure 15. Absorbed reactive power from wind turbine generators in the simulated benchmark system at 12:00.

To exemplify the dynamic behaviour of the ANM solution, resulting bus voltages from a simulation with the Q+P algorithm are shown in Figure 16. The appearance of a small voltage overshoot in the morning of the simulated day highlights the need for a closer inspection of the PI controller gain settings in the implementation phase so that the desired dynamical behaviour is attained even during fast changes in power output (in this case corresponding to a sharp increase in wind speed between 8:00 and 9:00, see Figure 12).

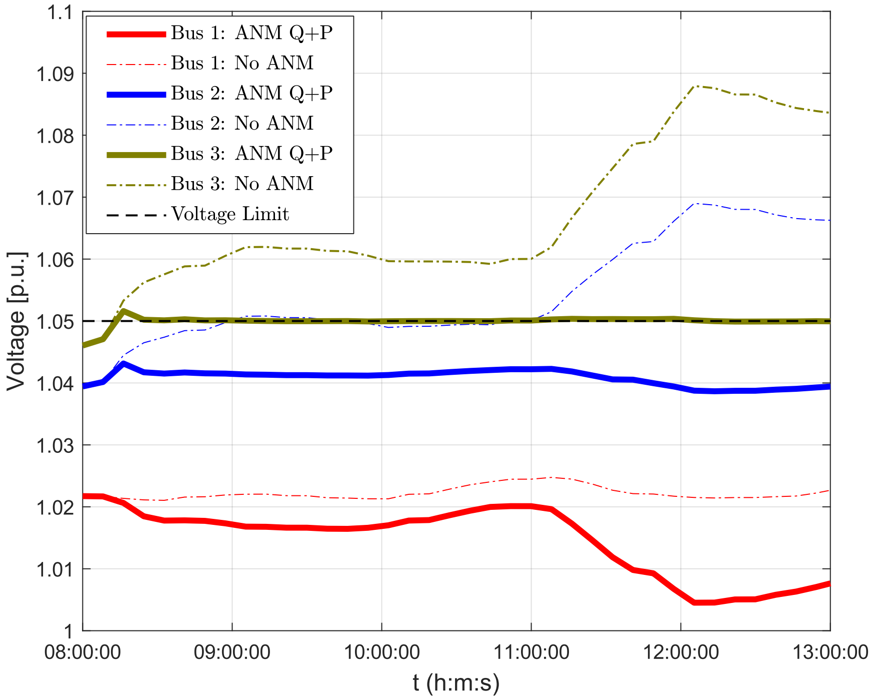

Figure 16. Simulated bus voltage changes from ANM Q+P control in the benchmark system.

Given the relatively small load demand at buses 2 and 3, the impact on voltage by an increase in the active power consumption, even a significant one, is negligible when the two wind power plants were present. To demonstrate the functionality of the ANM algorithm for flexible loads, the restrictions on the ANM algorithm increasing the load demand above the benchmark maximum were removed. Without the constraint present, it is possible to study the total demand needed to maintain the voltage within the network limits during the previously discussed mid-day conditions. One can also examine the interaction between the ANM load algorithm and the ANM wind power algorithms. The results from some simulated algorithms combinations are shown in Figure 17.

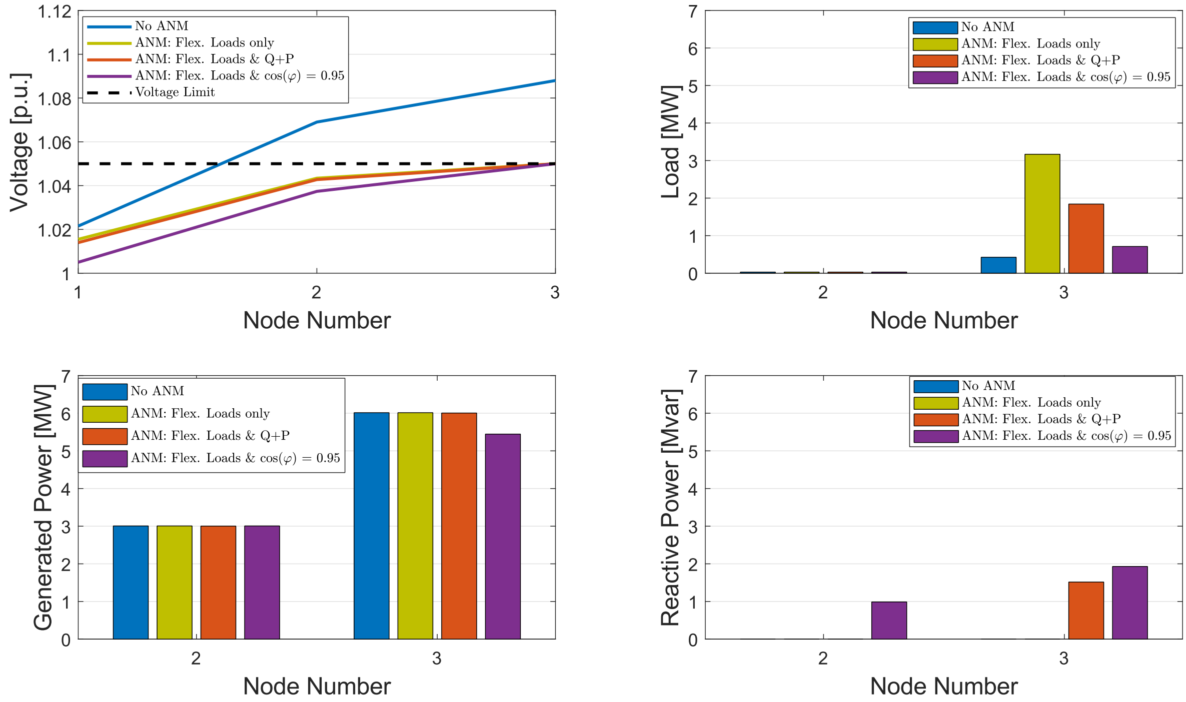

Figure 17. Simulation of benchmark system with ANM algorithm with flexible loads at 12:00. Voltage profile (upper left) - maximum allow grid voltage is 1.05 p.u. (dotted black line); load demand (upper right); generated wind power (lower left); absorbed reactive power (lower right)

Figure 17 shows that local consumption would have to be increased tenfold at bus 3 to limit the voltage if no actions are taken by the wind power plant controllers. Again, the local nature of the algorithm favours control actions at the end of the feeder, meaning the small load at bus 2 will not increase. It is evident that the use of flexible loads to some extent can reduce the curtailment of wind power, as seen when a constant power factor algorithm is applied. However, the lack of coordination between the flexible load and generation resources prevents the operator from prioritising specific control actions. Here, it would be desirable to increase consumption before considering curtailment. If the proper communications infrastructure is in place, this problem can simply be solved through a flexibility dispatch, similar to the approach taken with the ANM congestion management algorithm.

While the relative rise in load demand seen in Figure 17 is significant, in absolute numbers the increase is not as extreme. In a low voltage feeder where the installed distributed generation capacity is lower, EV chargers or smaller battery systems can be suitable for use as flexible loads to create a sufficient increase in demand.

4.4 ANM Congestion Management Algorithm Performance

The large power production at noon does not only affect the network voltage, but it also poses a network capacity challenge. As seen in Figure 18, the loading of the line exceeds the rated current on two occasions during the day if no control actions are taken. The overloading of the line notably coincides with large wind generation (see

Figure 12). Again, this makes using an ANM algorithm to control the wind power plants the natural choice, particularly if other flexibility resources are scarce.

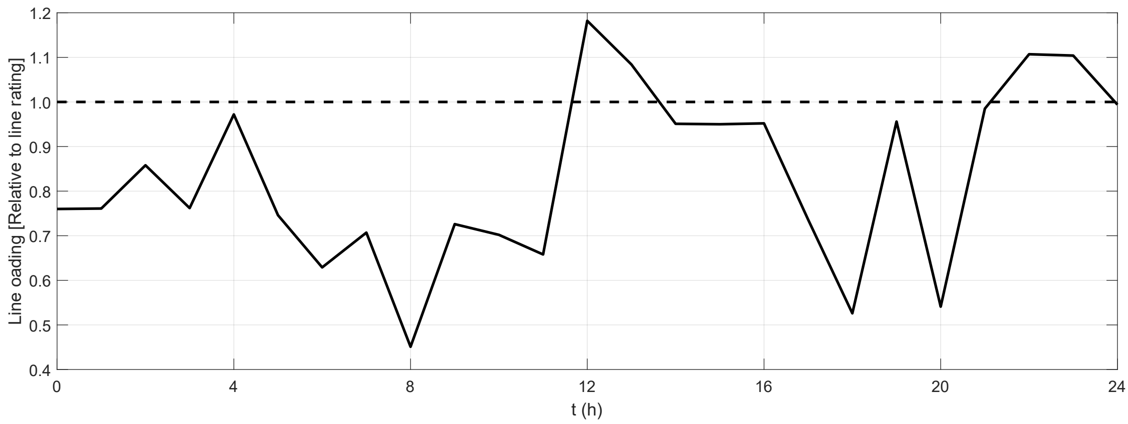

Figure 18. Simulated loading of the overhead line between buses 1 and 2 in the benchmark system.

The ANM algorithm for congestion management activates resources via the flexibility dispatch, which allows for different prioritisation schemes. Two options that have been tested are using power transfer distribution factors (PTDF) and equal sharing of the control action. While dispatch based on PTDF minimizes the total control effort, it shifts the control actions to the same resources due to the network topology. If variations in PTDFs between different resources are small, a more evenly distributed control effort might be desired. The results from a simulated congestion management scenario without ANM and with ANM using two different flexibility dispatches are shown in Figure 19. Note that no attention is paid to overvoltage issues in this example. In the first ANM case, PTDFs show that the wind plant at bus 2 has greater impact on the congestion than the one at bus 3. The difference is however very little and in the second ANM case, the curtailment is shared equally among the two wind plants.

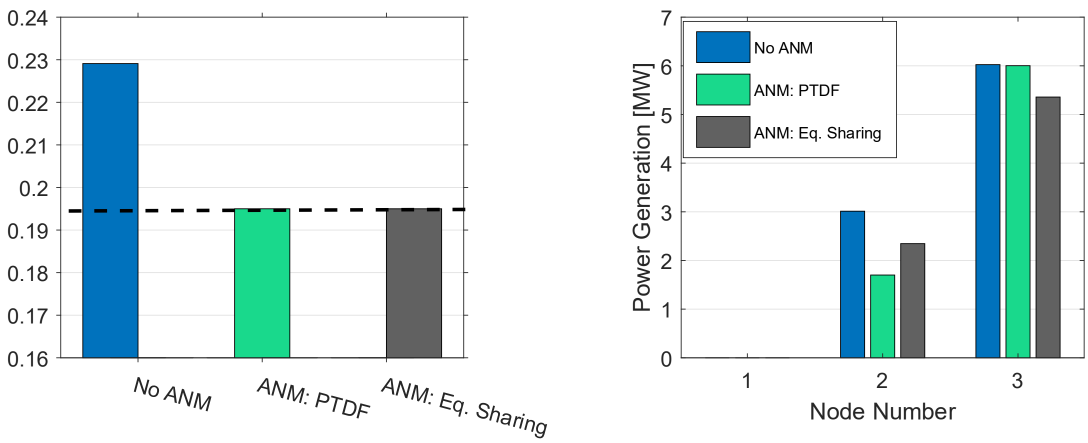

Figure 19. Simulation of benchmark system at 12:00 with ANM congestion management. Resulting line currents (left figure), with rated line current is 195 A, and corresponding active power injections (right figure).

Both alternatives can easily be modified. Instead of sharing the control effort equally in absolute numbers between the flexibility resources, equal relative changes in active powers can be used. For the simulated scenario, this would mean that both wind plants are instructed to curtail the same percentage from their output. The use of PTDF can be complemented by additional constraints to distribute the control effort more evenly. The algorithm modified to limit the curtailment to maximum absolute number or be proportional to the output. It would force both wind power plants to contribute to the congestion management. In Figure 20 below, the dynamics of the PTDF-based ANM algorithm is exemplified.

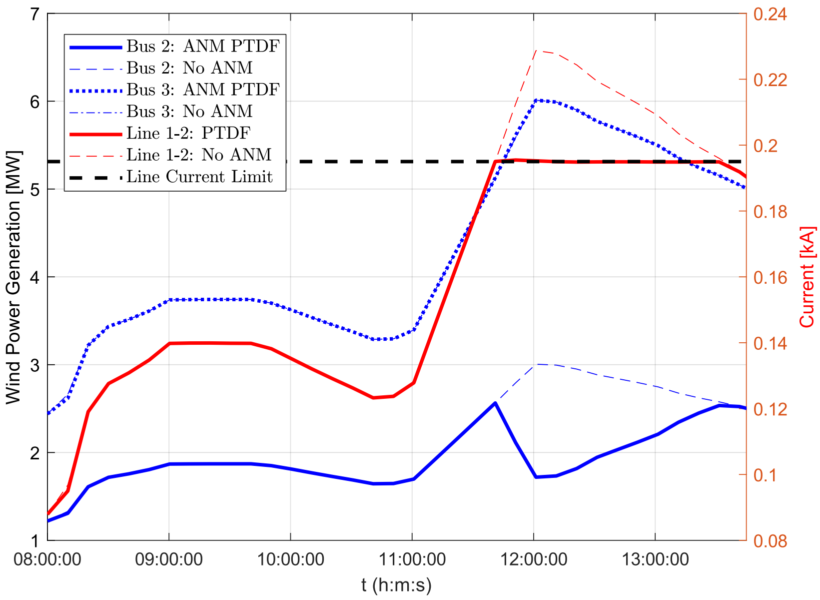

Figure 20. Simulated line current change from ANM congestion management algorithm in the benchmark system. Flexibility dispatch is based on PTDF, which affects wind power generation only at Bus 2 so that the two curves for Bus 3 coincide.

Flexible loads can also be included in the congestion management algorithm, which provides an opportunity to reduce curtailment. It adds a second step to the control action prioritisation scheme, meaning control efforts would not only be distributed based on bus location but also on asset type.

4.5 ANM Reactive Power Management Algorithm Performance

As shown in section 3.4, the congestion management algorithm can be converted to manage reactive power flows by changing the controller input signals. In the example in Figure 21, the reactive exchange between the radial feeder and the overlying HV network is measured. At 08:00 in the simulated day the ANM algorithm is activated and quickly brings the reactive power flow from the HV network to zero from a starting point of significant magnitude. During normal operation, the feeder reactive power demand is driven by the large load at bus 1. In this example, the flow of reactive power is measured at the MV-side of the HV/MV transformer and for simplicity the control effort is divided equally between the wind plants.

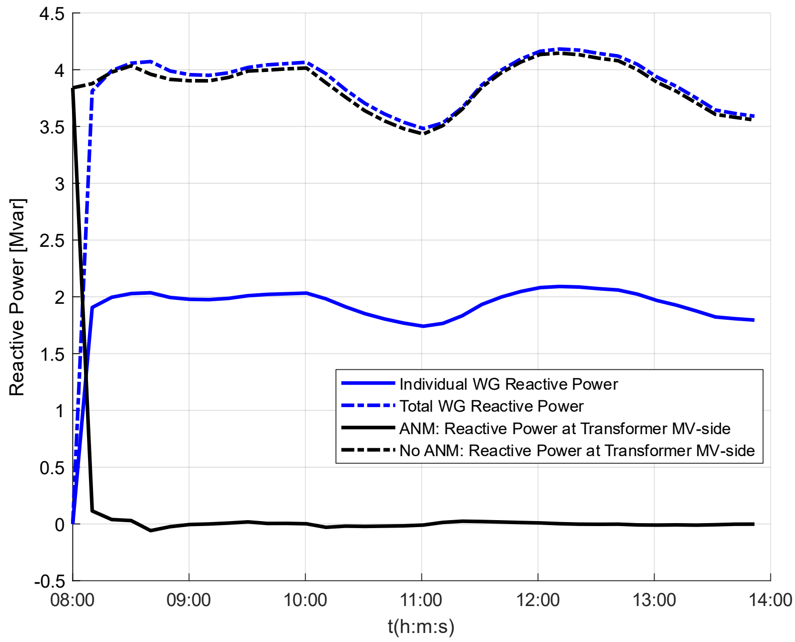

Figure 21. Simulation benchmark network with ANM reactive power management algorithm at 12:00.

Using a local reactive power dispatch reduces the loading of the transformer and aids the DSO in reducing costs associated with excessive reactive power exchange with the HV network if such limits exist. It is important to note that extensive use of the reactive power management algorithm might have a negative impact on voltage limitation and congestion management efforts. As it is essential from a safety and reliability perspective to successfully achieve the latter two objectives, they should be prioritised over reactive power management in case of conflicting actions.

5 FURTHER DEVELOPMENT OF ANM ALGORITHMS

Some additional topics related to the presented ANM solutions are briefly discussed in this section. The first is on data needed from algorithms to show the actions of participating resources. The data could be used by the DSO to evaluate the performance of ANM algorithms in operation, and for short- and long-term network planning purposes. The information about actions taken by flexible resources could also form the foundation for a financial reimbursement solution for participants in an actively managed network. The last aspect is not the focus of this report, but nevertheless an important factor in a real-world implementation, and closely linked to the structure of the algorithm in use.

The second topic is concerned with the interaction between different ANM algorithms. In the previous sections, voltage and current constraints have been treated separately, while in actual network planning and operations they must be considered simultaneously. In section 5.2 a first step of the algorithm merging process is exemplified in which control of active power output from PV units in a low voltage network is coordinated.

5.1 Algorithm Data Availability and Financial Solutions

Gaining access to flexibility resources is vital for a functional ANM solution. Asset owners might be required to provide certain network services according to grid codes or a legal framework. An alternative is a market-based solution where flexibility can be traded (as described in Chapter 3), thus giving asset owners a financial incentive to actively participate in network management. In any case, it must be possible to extract information about how that the ANM algorithms actually utilise each resource. If flexibility is required by grid codes, this is compliance monitoring, while in the market case it is part of the financial settlement.

The ANM algorithms are designed to operate in near real-time and set points are updated at every sampling instance. The resolution of the data that can be used in a market-based system will depend on the ANM algorithm parameters. As the asset controllers always provide ΔP and/or ΔQ, both the duration and magnitude of control actions can easily be recorded. If the time it takes to reach steady state after a set point change is negligible with respect to the sampling interval, the utilised energy from a flexible resource that is utilised by ANM can then be calculated as

$$Energy_{Flex\ Resource} = \sum_{i=1}^{n} |\Delta P_i| \cdot t_s \ ,$$

where n is the number of data samples, $|\Delta P_i|$ is the magnitude of the ANM control signal at sampling time instance i, and t_s is the sampling time. A similar approach is possible when examining the injection or absorption of reactive power over time. If the dynamic behaviour is to be studied in closer detail, the product in the equation above can be replaced by a function modelling the dynamics between two samples ΔP_j and ΔP_{j+1}.

Lastly, it is worth noticing the difference between a local ANM controller and centralised ANM control in terms of potential market solutions. Without coordination, the distribution of control actions is largely predetermined as the choice of algorithm and associated parameter settings play a large role. A centralised system on the other hand allows the operator to choose from multiple control actions, meaning several control objectives are available through manipulation of the flexibility dispatch list. Objectives include minimization of curtailment, power transfer losses, costs, or the environmental impact, and can be achieved through prioritization based on asset characteristics and location in relation to the network topology and specific grid constraints.

5.2 Combining ANM Algorithms

Network operation within both voltage and current limits is normally a requirement, with or without an ANM solution present. The algorithms described in previous sections have been developed to manage issues related to separate constraints, which does not necessarily mean they are able to run in parallel. If multiple constraints are occurring simultaneously and the responses from different ANM controllers are conflicting, there is a risk that the network will be exposed to unfavourable or even harmful operating conditions. To avoid such a scenario it is necessary to, when combining the discussed ANM algorithms in operation, establish a protocol for constraint prioritisation.

By prioritising the strictest constraint, the ANM algorithms can simultaneously manage both voltage and congestion using the same active power flexibility resources. This is illustrated in the example below, where curtailing the generation that causes overvoltage and congestion works to solve both problems. Adding reactive power capabilities to the combined ANM algorithm increases the control complexity and will be considered in the continued work within the ANM4L project. Using reactive power to reduce voltage might counteract congestion management efforts, and lead to an increase in curtailment or flexible load demand. Similarly, managing the reactive power balance in a transformer using reactive power from wind turbine generators, may cause voltage issues at them.

The outcome of how these issues combine depends on the ANM algorithms but ultimately on the physical properties of the network with connected loads and generators. Considering line impedance, congestion is related mainly to the cross-sectional area of line conductors, while voltage issues depend on that too, but also on the length of the same conductors. Considering an increasing amount of local generation, a short feeder is therefore likely to exhibit congestion issues before voltage issues, while the opposite holds for a long feeder. When voltage problems occur on the short feeder, managing them with reactive power is not possible as congestion excludes increased currents.

A combined ANM algorithm for voltage limitation and congestion management using only generator curtailment is shown in Figure 22. The centralised congestion management algorithm has been superimposed with the curtailment part of the local sequential voltage limitation algorithm for renewable energy sources to create the combined algorithm. In this case curtailment can be used to mitigate overvoltage as well as overloading of network components. Each local controller has an additional control signal selection that prioritises the control action – required by voltage management and congestion management respectively – that gives the largest ΔP. This corresponds to the strictest constraint, or in other words the minimal curtailment needed to both prevent overvoltage and give the required individual contribution to the coordinated congestion management.

Initial simulations of combined ANM algorithm have been performed on a low voltage test feeder, see Figure 23 [27]. The algorithm was deployed to simultaneously prevent overvoltage at the end of the feeder and overloading of the MV/LV transformer.

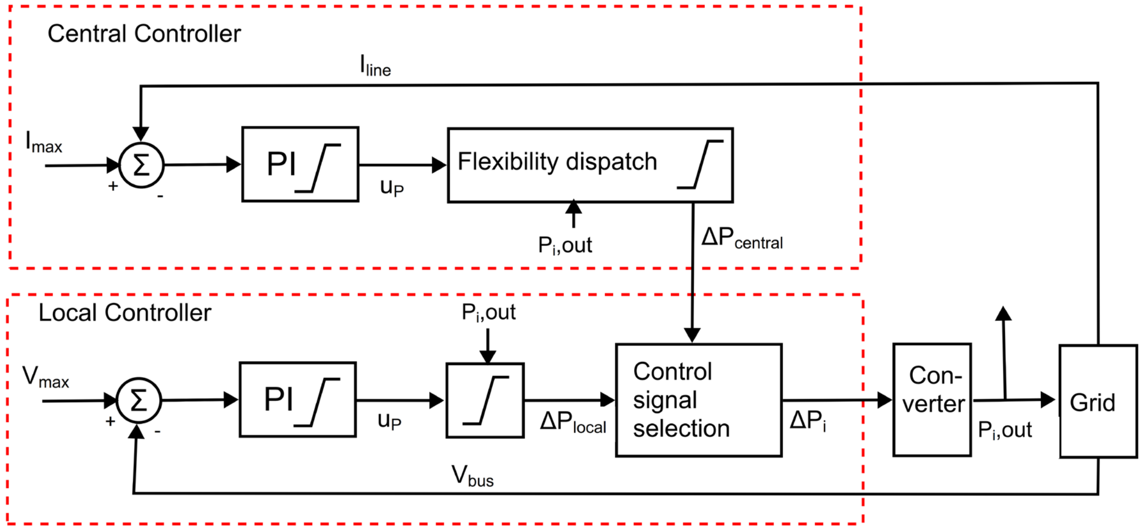

Figure 22. Combined voltage limitation and congestion management ANM algorithm block diagram. Note that there is one Local controller at each PV installation, but only one Central controller.

The test feeder consists of five households with identical 30 kW roof-top PV installations. A simplified daily generation profile with interpolated hourly values was used, and it was assumed that the load demand is negligible in comparison to the generated power during the time of study.

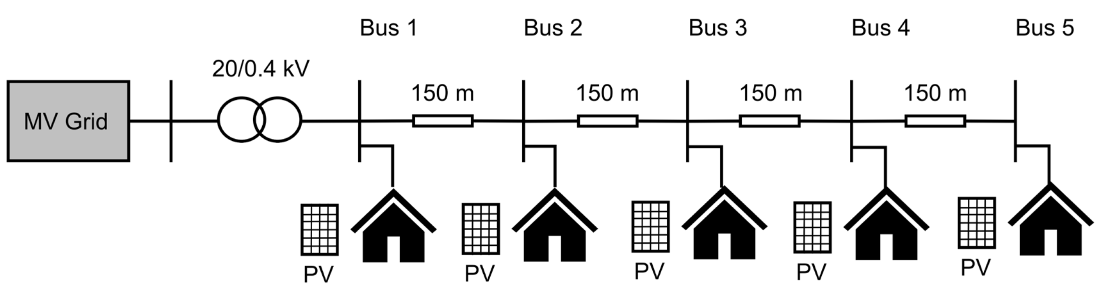

Figure 23. 5-bus LV test network. The five households have identical 30 kW roof-top PV installations.

The feeder model was implemented in *SIMULINK* with the *SimScape Electrical* toolbox. The MV Network was represented by a Thévenin equivalent circuit, and a dynamic ANM controller model was used for simulations. A flexibility dispatch where resources were given a random ranking was included for congestion management. The dispatch list, shown in Table 5, also include the maximum curtailment level that each unit is willing to provide.

Table 5. Dispatch list for 5-bus LV network with flexible PV units.

Flexibility dispatch		
Ranking	**PV unit number**	**ΔP limit [% of rated P]**
1	3	20
2	1	30
3	4	30
4	2	60
5	5	100

Results from simulations of the LV test feeder, shown in Figure 24, shows the capability of ANM algorithm to limit the voltage at bus 5 to the maximum allowed 1.1 p.u. during the PV peak production hours at mid-day. The algorithm can simultaneously control the current through the MV/LV transformer, as seen in Figure 25.

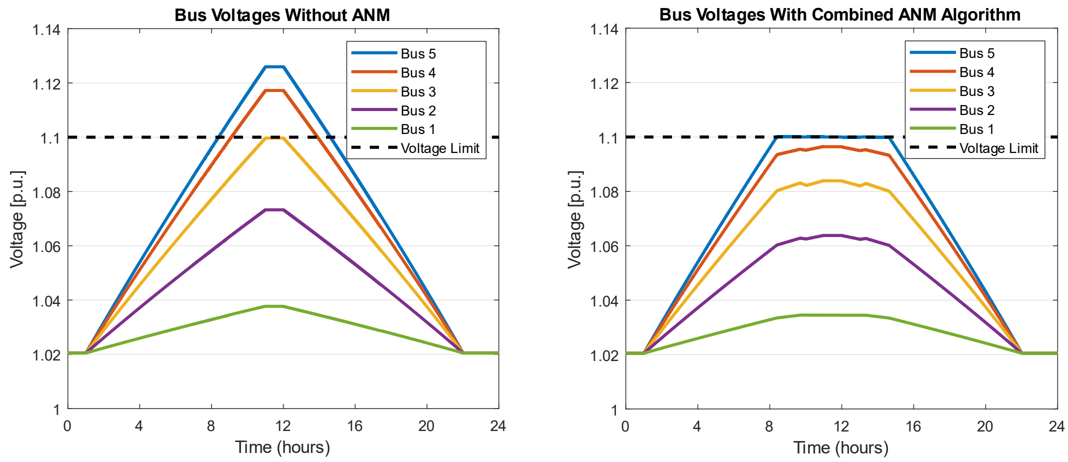

Figure 24. Simulation of LV feeder bus voltages without ANM (left) and with combined ANM algorithm (right).

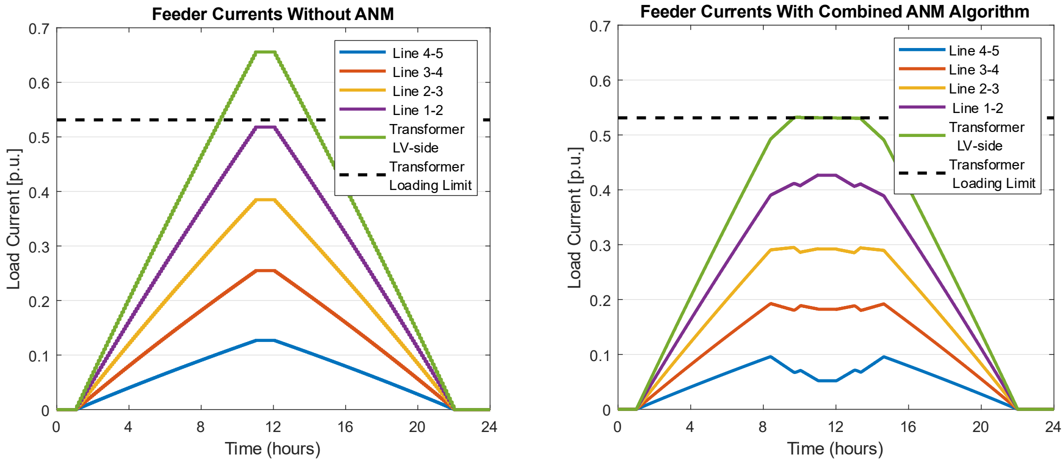

Figure 25. Simulation of LV feeder currents without ANM (left) and with combined ANM algorithm (right). The corners on e.g. the red curve in the left plot are associated with voltage limit at bus 5, transformer current limit, voltage limit at bus 4 later repeated in reverse order.

In this case, the voltage limitation part of the algorithm is activated first, as the voltage limit is reached before the current limit in the morning. As the local algorithm in this simple case cannot adjust reactive power it gradually curtails the PV unit at bus 5 where the voltage increase is most significant. The curtailment actions by the different PV units throughout the simulated day can be seen in Figure 26.

As the total generated power keeps rising, the congestion management part is also initialised. The PV unit at bus 3 is ranked highest, followed by the unit at bus 1. The curtailment limit for the PV unit at bus 3 is quickly reached, which initiates curtailment at bus 1. The added control actions temporarily halts the increase in curtailment for voltage limitation purposes at the end of the feeder, also seen in Figure 26. However, since the total generated power continues to increase up until noon, curtailment at bus 5 must be increased again to limit the voltage. This in turn positively impacts the loading situation which reduces the need for actions by congestion management part, which means no actions are needed from the PV units at buses 2 and 4. In the afternoon the reverse process takes place due to the symmetry of the generation profile.

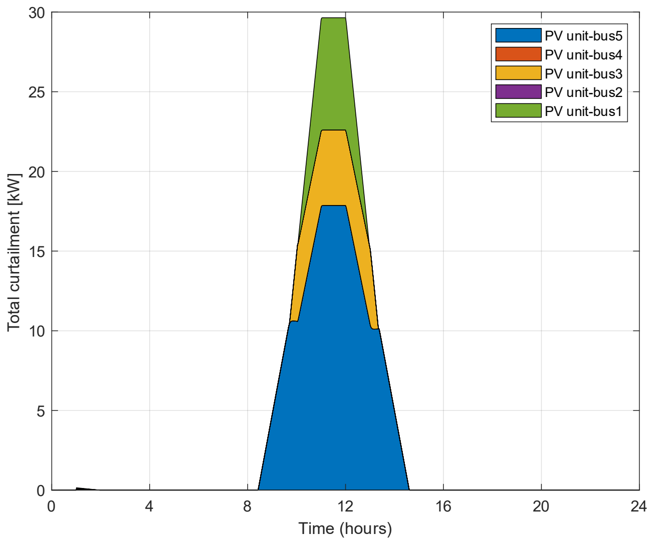

Figure 26. Cumulative curtailment of PV units in LV test network simulation.

The combined ANM algorithm example shows how congestion management and voltage limitation can simultaneously be achieved. For the radial LV feeder, local voltage control actions have been given priority and preventing overloading of the transformer becomes an operation mainly concerned with correcting offsets created by the voltage limitation part.

6 DISCUSSION

The main issues associated with large-scale integration of renewable energy sources presented in this report are overvoltage and overloading of network components. The purpose of the developed active network management algorithms is to mitigate these two issues to increase the renewable energy penetration while maintaining reliable network operation conditions. This is made possible through control of the active and reactive power output of flexibility resources, which include inverter-interfaced distributed generators, flexible loads, and battery energy storage systems.

The algorithms are intended to be easily deployable, scalable, and adaptable to different networks and therefore simplicity was favoured over optimality in the development process. The algorithms are derived from a basic structure, which includes a PI controller and an input signal that is computed from limit values rather than a reference value. This makes it possible to safely operate the network within voltage and current limits.

Overvoltage typically occurs at the end of radial distribution feeders in times of coinciding large power production and small load demand. Voltage issues tend to be most efficiently managed at the location of occurrence, which makes the problem local in nature. Consequently, a local voltage limitation ANM algorithm was developed. It uses both active and reactive power when available, either sequentially or with a constant power factor. A version was adapted to loads with only active power control.

While renewable energy sources can be spread out through the distribution network, bottlenecks are normally located close to or at the point of connection to the overlying transmission network. This makes a simple, purely local solution infeasible, and a central ANM congestion management algorithm was therefore developed. Through the algorithm, control actions are distributed via a flexibility dispatch to participating flexibility resources. A separate version of the congestion management algorithm was created to manage the flow of reactive power through an identified interface typically in a transformer.

Finally, combined voltage limitation and congestion management was presented, and it was demonstrated how these can be used to simultaneously control voltage locally and manage a network bottleneck in a centralised configuration.

CHAPTER 3: CHARACTERISATION OF FLEXIBILITY RESOURCES

(ANM4L DELIVERABLE D4.2)

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1 FLEXIBILITY RESOURCES

In this chapter we present resources that can provide flexibility in an ANM solution. The purpose is to allow for a larger share of renewable generation without investments in grid reinforcement due to capacity and voltage problems. The focus of the ANM4L Project and this report is on the Swedish and Hungarian demonstrations that will be performed later in the project.

Most flexibility resources covered in this report are listed in [28] where they are described in more detail.

For each flexible resource, the following is defined:

- who is the counterparty to the DSO,
- the estimated cost of using the resource,
- what type of service it provides, and
- its availability, response time and possible duration of flexibility.

The counterparty, if not the owner of a resource, can be an aggregator. An aggregator is a company or organisation that aggregates resources and provides flexibility to the DSO.

For a manually activation of a flexibility resource any response time below a few minutes is negligible compared to the time it takes for an operator to take a decision. Therefore, all flexibility resources with a response time below a few minutes can be considered equal from a response time perspective.

For an automatically activation and control of a flexibility resource the response time may need to be in the range of seconds, depending on the control algorithm. In Chapter 2, the sampling interval was set to 10 seconds for some examples. If the flexibility resource is connected via power electronic converters the response time is fast, normally in the range of milliseconds. Other flexibility resources might have a longer response time and can also have a maximum ramp rate that needs to be considered for the control algorithm. This needs to be investigated and verified for each specific flexibility resource that will be included in an ANM solution.

An overview of the characterisation for the flexibility resources is presented in Table 7.

1.1 Generation control

1.1.1 Active power curtailment

The active power, due to the low X/R-ratio in the distribution grid, leads to a voltage rise at the point of connection of the DG. There can also be overload of lines/cables due to the active power. To avoid a voltage rise or to avoid overload the active power from the DGs can be curtailed. The response time is in the range of milliseconds or seconds depending on the type of turbine.

Without storage, this energy is not possible to shift to another time of consumption and therefore it means spilling a part of the available energy from sources as wind parks and PV plants. Active power curtailment should be used first after the DG has depleted its capability to reduce the voltage by reactive power consumption or by other means in the grid.

The counterparty of the DSO when it comes to the DG is the owner of the power source or an aggregator.

For the PV plant the cost for curtailing is the loss of sold production. If the exact cost is unknown, this can be proxied as the spot price multiplied by the curtailed energy. There is no extra cost, such as mechanical wear and tear, for curtailing a PV plant.

For the WTG one cost for curtailing is the loss of sold production. As for the PV, if the exact cost is unknown this can be proxied as the spot price multiplied by the curtailed energy. Another cost for curtailing WTG stems from the mechanical wear and tear. There is one cost for curtailing, turning the blades, and an additional cost for shutting the WTG down.

1.1.2 Reactive power generation and consumption

Reactive power is used to control the voltage magnitude. Due to the low X/R-ratio in the distribution grid both active and reactive power influences the voltage magnitude.

DG with power electronic converters have reactive power capability integrated into the converter's control features and can therefore control the reactive power and contribute to the voltage control without any additional reactive power equipment. They can both generate and consume reactive power and the capability is limited by internal voltage, temperature, and current constraints. Therefore, the amount of reactive power the converters can provide decreases as the active power generation increases. The response time is due to power electronic converters fast, in the range of milliseconds and reactive power can normally be provided as long as the power plant is connected to the grid.

DGs without capabilities or limited capabilities to provide reactive power normally have other reactive power equipment such as capacitor banks installed in the power plant to fulfil the grid code requirements.

The counterparty of the DSO when it comes to the DG is the owner of the power source or an aggregator.

For PV plants and WTGs that can control the reactive power the cost for reactive compensation is the potential reduction of active power, i.e., loss of sold production. If the exact cost is unknown, this can be proxied as the spot price multiplied by the curtailed energy. There is no extra cost, such as mechanical wear and tear, for reactive power control.

Price of electricity produced in a wind park is not necessarily equal to the spot price however for simplicity we use the spot price as a proxy.

1.2 Flexible consumers

The voltage can also be adjusted in the distribution grid by controlling the load in the grid. Not all types of loads can be used for this control method, typically it should be loads with limited impact on the comfort for the users, suitable types include loads with slow dynamics typically with thermal storage such as ventilation, heating/cooling. Charging of electrical vehicles can also be considered.

Load control can be used both for preventing overload and to maintain bus voltages. To be able to regulate the voltage both up and down and to prevent overload the loads need to be controlled in both ways, both a reduction and an increase of the active power consumption is desirable. It is not necessary that each individual load can be controlled in both ways, however the portfolio must be able to respond efficiently to both needs.

During the demo case in Sweden that is planned in this project there are plans to include heat pumps and electrical vehicles as controllable loads. These are both described below but there are of course other loads that could be used. Most loads that can be shifted in time have a similar cost as heat pumps and electrical vehicles.

Other loads that could be relevant to act as a flexibility resource are electrolysers (for hydrogen production), desalination plants (there is one on Öland), electric energy storage (hydro pumping, compressed air, flywheels, hydrogen, batteries, supercapacitors etc), etc.

Shifting power consumption in time is rarely expected to lead to increased (or decreased) electricity costs. Rebound of power should however be considered if the load is turned off/reduced and needs to be turned on. The load might need more power after than before it was turned off/reduced.

1.2.1 Charging infrastructure of electrical vehicles (EV)

It is here assumed that the EVs cannot push energy back to the grid, i.e., V2G. In a future scenario this may be possible and relevant to explore.

EVs are loads that potentially can be controlled for utilization as a flexible resource. The owner can be the DSO, a company, or a private individual. To avoid too many contracts for the DSO, EVs are preferably controlled by an aggregator. The response time should be below one minute but probably faster depending on the type of charging equipment and the communication protocol and the system architecture of the charging equipment.

If the user of the EV is always charging the vehicle with the highest possible power this resource can only be used for reduction of active power consumption.

One cost for utilizing EVs as a flexible resource is the difference for the hourly spot price when charging, meaning that the cost can be both positive and negative. Further, there is a cost of inconvenience for providing the resource as a flexibility resource, as the EV may not be fully charged when needed. This cost needs to be considered when paying for utilizing the resource. No other costs exist, because it is automated and always active there are no extra mechanical wear and tear, no loss of income nor any additional technical cost.

1.2.2 Heat pumps (Residential)

Heat pumps are also loads that potentially can be controlled for utilization as flexible resources and can be controlled by the owner. The owner can be the DSO, a company, or a private individual. To avoid too many contracts for the DSO heat pumps are preferably controlled by an aggregator. The response time should be below one minute but probably faster depending on the communication protocol and the system architecture for the control of the heat pumps.

If a heat pump is turned off it normally consumes more power upon reactivation compared to before it was turned off, there is a rebound of power which is important to take into consideration.

There is a cost of inconvenience for providing the heat pump as a flexibility resource, because the in-door temperature can both become higher and lower than desired. This cost needs to be considered when paying for utilizing the resource.

Other costs for utilizing heat pumps as a flexible resource are here estimated to be zero because the energy is only shifted in time, there are no extra mechanical wear and tear for using it since it is automated and always active, no loss of income nor any additional cost. The only cost is the difference for the hourly spot price when heating, it means that the cost can be both positive and negative.

1.3 Equipment in the grid

Equipment in the grid can help to maintain voltage limits throughout the network as well as avoiding overload situations. They will be activated when needed to avoid an unwanted situation in the grid and, if possible, activated before the loads and production resources in the grid are affected.

1.3.1 Transformer tap changer

There are both no-load tap changers (NLTC) and on-load tap changer (OLTC) in the grid. NLTC requires the power to be cut before operated and might therefore not be relevant for an ANM solution. The OLTC can be managed during operation and are normally operated by an automatic voltage control relay that decides the position of the tap changer. If the OLTC tap changer is of online type it can be operated remotely from the control room. The OLTC is always available where it is installed in the grid but the possibility to use it to depends on the rating and the actual position of the tap changer. The response time and the time for the tap changer to change position is in the range of minutes.

Tap changers are owned and controlled by the DSO and the cost for operating them stems from the mechanical wear and tear.

The cost for using NLTC is higher than for OLTC due to manual on-site operation of the equipment and cut of power but the equipment is excluded in this context.

1.3.2 Line Voltage Regulator (LVR)

A Line Voltage Regulator (LVR), also known as Series Voltage Regulator, can be used in a distribution system to have control over the voltage for an individual feeder without affecting other feeders in the grid. The LVR is always available where it is installed in the grid but the possibility to use it to depends on the rating and the actual position. The response time is in the range of minutes.

Line Voltage Regulators are owned and controlled by the DSO and the cost for operating them stems from the mechanical wear and tear.

1.3.3 Reactive power compensation equipment

The reactive power can be controlled by shunt capacitors and reactors, STATCOMs, SVCs and similar equipment. Shunt capacitors and reactors provide static passive compensation, and they are either permanently connected or possible to switch. STATCOM and SVC (Static Var Compensator) devices provide active compensation, have fast switching capability and can both absorb and provide reactive power. The response time is the range of milliseconds.

Equipment for reactive power compensation is normally used and owned by the DSO. There can also be reactive power equipment installed in a power plant to fulfil grid code requirements.

The cost for operating them stems from the mechanical wear and tear. Switching of shunt capacitors/reactors can also cause stress on other electrical equipment in the grid.

1.4 Flexibility enabler

There is equipment, such as information communication technology and measurement system, that do not provide flexibility, but that enable flexibility to maintain voltage limits throughout the network as well as avoiding overload situations. The monitoring system for dynamic line rating (DLR) is part of the Swedish demo and therefore included in this report.

1.4.1 Dynamic Line Rating (DLR)

Dynamic line rating (DLR) is a method to maximize the ampacity of the powerline/cable depending on the environmental conditions, without compromising safety. The benefit is that more power can be transferred compared to if a static nominal rating of the powerline/cable would have been used. DLR is always active and therefore available to be utilised for the powerline/cable it is installed, but the output is dependent on external factors such as outdoor temperature and wind.

The equipment is owned by the DSO and the output defines the maximum transfer capacity.

The utilization cost for DLR is zero because of three reasons. First, the DSO owns the equipment. Second, there is no mechanical wear and deterioration for using it since it is automated and always active. Third, there is no loss of income nor any additional cost.

2 FINANCIAL MODELS

While the ANM4L project focuses on developing solutions enabling integration of renewables with the agility required from developments in demand and production, it is by necessity also discussing the basis of a local flexibility market. The market is needed to make the solutions available to the DSO and sets the rules for how flexibility is traded. In this chapter several options are discussed. Regardless of market solution, the goal is to optimize the usage of flexibility and thereby maximising the integration of renewables.

For the demonstrators of the ANM4L project, flexible resources will be directly controlled by the DSO. Task 4.2/MS4 elaborates on possibilities for how the DSO can procure flexibility services from flexibility providers from a theoretical perspective in the future.

The first section of this sub-chapter briefly reminds the reader of the definitions of demand side management (DSM) and demand response (DR) used by the ANM4L project. The second section discusses some of the fundamental market requirements to take into consideration when deciding which financial model to apply. The third section elaborates on 2.1 and describes DR and DSM in relation to the market and presents options available under DR and DSM respectively, and finally the fourth section discusses the pros and cons of different options for different types of flexibility resources.

2.1 Energy demand management

There are different flexibility solutions related to customers in the grid, demand side management (DSM) and demand response (DR). Both provides the DSO with the ability to increase or decrease e.g. household power consumption, thus making residents direct contributors and part of the solution by adding grid supporting flexibility. [28]

The differentiation between DSM and DR are agreed within the ANM4L project. In this deliverable the description and definition of these expressions are expanded, and the market arrangement for both involve any flexible resource.

2.1.1 Demand Side Management (DSM)

In the case of DSM (direct DSO activation), a contractual bi-lateral agreement between DSO and customer, or other relevant counterparty, can allow the DSO to instantly access and activate a flexibility resource upon demand.

2.1.2 Demand Response (DR)

In case of the market-based approach DR, flexibility requests and offers are matched in a market enabling the DSO to procure flexibility upon demand for a specific hour. This can be done by aggregators handling the bidding and end-customer activation to ensure adequate pricing, efficient allocation, and access to flexibility. This is a more complex approach with numerous interactions and limited number of market participants for liquid transactions. [28]

2.2 Asymmetric information and willingness to participate

The purpose of the financial model is to financially connect the DSO and the flexibility provider. However, some fundamental market requirements[2] must be fulfilled for the market to function efficiently. Two relevant topics will be described in this section: Asymmetric information and marginal cost versus price.

First, at least initially, there is asymmetric information where the DSO has access to relevant information that the seller does not. This is due to the role of the DSO as network owner and the traditional role of consumers that now turn sellers. The seller does not have access to the same detailed information nor have knowhow needed to interpret information. This may for example cause issues when the seller must rely on the DSO to gain knowledge on their sold quantity of flexibility.

Furthermore, the level of available information and knowhow is likely to vary among different types of sellers of flexibility. A company owning a wind park is likely to be better informed and to have more resources to invest in knowledge compared to the average household. However, the household (as well as companies) may be able to use the services of an aggregator. Such an agent may be able to bridge the information-gap.

Second, the price must be right. For the seller to be willing to participate on the market, the price must be equal to or higher than the marginal cost and at the same time it must meet the willingness to buy of the DSO. The definition of marginal cost is the cost of supplying one extra unit and is bound to differ between resources.

The price of flexibility will be determined by the market, through negotiations between actors (in the DSM and potentially the DR solution) or auctions (in the DR solution). This report does not discuss specific mechanisms, but instead focus on the willingness to pay and buy of the parties, the providers of flexibility and the DSO.

Upon deciding on the most efficient solution to a congestion problem the DSO must perform a two-step analysis. First, at some point in time, the DSO has decided how to tackle the problems they are trying to solve using flexibility resources. This decision process is described in Chapter 1 and consist of a CBA analysis comparing ANM solutions to reinforcement of the grid. Second, assuming the DSO decided to go with the ANM solution and exploit available sources of flexibility in the grid, the DSO must have a strategy upon deciding when and which resources to activate and/or request. There are multiple factors that determine whether a resource is suitable to help solve a situation or not, both locational and technical aspects are pivotal and therefore ahead of cost, see Figure 27. The remaining subset of resources are then prioritised based on cost/price. One may think there are no costs associated with utilizing equipment in the grid as these are owned by the DSO,

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2 All criteria for perfect competition will not be described in detail, however they include: a homogenous product, that all agents are price takers and that market shares do not influence price, perfect information, and free entry and exit.

however this is not the case. The costs consist of for example mechanical wear and tear and it is important that these costs are taken into consideration.

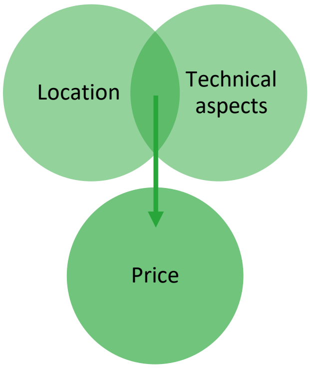

Figure 27: Order of events

2.3 Options under DSM and DR

The Council of European Energy Regulators (CEER) highlights four alternative ways for the DSO to access flexibility [29]:

- a rules-based approach,
- through connection agreements,
- by using network tariffs, and
- through market-based procurement.

The ANM4L project focuses on the latter, which under the assumption of perfect competition and sufficient market liquidity will offer efficient solutions. Both DSM and DR are available as the market-based approach include bilateral negotiations, organized marketplaces, aggregators etc. [29].

Under both DSM and DR, aggregators are likely to play an extremely important role in organizing trade and enabling flexibility exchange. They are however not discussed in detail in this report.

2.3.1 Options under DSM

A DSM solution leaves limited control to the flexibility provider (seller) and the DSO can, given a number of constraints depending on the resource, access the flexibility on demand. Here, three remuneration options are investigated: A flat rate contract, a flex rate contract, and a combination of both.

- The flat rate contract is independent of usage, the DSO reimburses the seller with a fixed amount and can, given a number of constraints such as indoor temperature if the flexibility resource is a heat pump, access the flexibility and activate the resource when need occurs.

- The flex rate contract is fully dependent on usage. The seller receives a remuneration of a predefined amount (can for example be a fixed amount or dependent on the spot price) times the used kWh.
- The combination consists of a flat base reimbursement and an additional kWh rate.

The main difference between these options is the risk allocation. With a flat rate the DSO takes on all risk because the cost is constant regardless of need. With a flex rate, the seller takes on all risk because the cost for the DSO fully correlates with need and usage, and the seller cannot be certain to recover costs of any investments made. With a combined rate the risk is shared between the DSO and the seller. How the risk is allocated under the combined rate depends on the distribution between the fixed and flex part of the contract. The larger the share of the fixed rate the more risk is allocated to the DSO and vice versa.

Table 6: Risk allocation

	Flat rate	Flex rate	Combined rate
Risk allocation	DSO	Seller	Shared

There are pros and cons with all solutions. On the downside, contracts are costly to establish and maintain from an administrative perspective. Therefore, it would be convenient with an independent aggregator to facilitate the relationship between the potentially many sellers and the DSO. On the upside, contracts do not require any trading platform to match bids.

The ANM operational tool should aim to optimize and activate the most cost-efficient combination of flexibility resources and must therefore take cost per kWh for each resource into consideration. The cost should be stated in the contract, hence there is no need for a trading platform.

2.3.2 Options under DR

In contrast to the DSM solution, the DR solution leaves more control to the flexibility provider and is dependent on usage. Instead of a long-term contract, the terms of trade are defined on a case-by-case basis where flexibility providers place bids that the DSO can chose to accept or not accept depending on its willingness to pay and other available offers.

The bid holds information on how much flexibility the provider has to offer, at what cost, and when. An owner of a wind park may for example not always accept being curtailed and the resource may therefore not always be available. However, since the flexibility provider price their resource themselves, their willingness to sell is reflected in the bid.

The design of auctions and price mechanisms are not covered in this report, however, as these are local markets, liquidity is likely to become an issue, and is therefore discussed next.

Liquidity is important for a market to function effectively. An illiquid market will likely result in insufficient amounts of flexibility and/or excessively high prices for flexibility. While liquidity is not directly observable and there is no generally accepted measure, it can be described as how easy or difficult it is to trade in a market. The trading volume is often used as a proxy. If the market is liquid, it is easy to trade, and otherwise it is difficult to trade. It is a function of many parameters, but high numbers of participants and transactions are positive. [30]

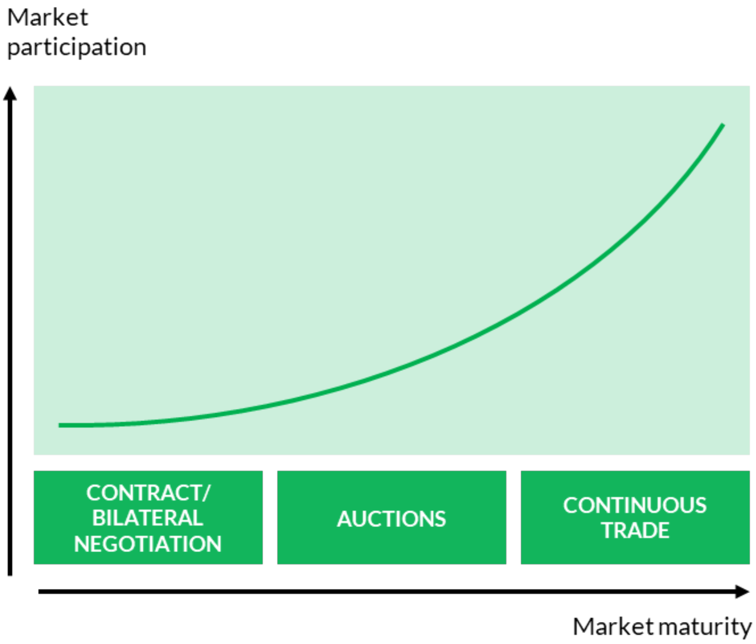

Figure 28: Market participation, maturity, and type of market organisation

While bilateral negotiations or contract-based solutions are inconvenient as many potential flexibility providers will result in an administrative burden for the DSO, they may be the most suitable way to go about organizing this market while the number of potential flexibility providers are few and the market is immature. The main reason is that the liquidity is likely to be too low to be able to support auction-based clearing mechanisms. While the administrative burden per contract is high, there is no need for advanced market platforms or the like.

As the market matures and more participants get involved, it can transfer into auction-based trade. There are different type of setups and coordination mechanisms to consider. To mitigate a potentially low liquidity, discrete auctions are suitable because these gather participants at the same time. As the market matures further and becomes more liquid the frequency of auctions can increase until it eventually makes sense to cross over into continuous trade, see Figure 29. However, some markets do not reach a level of liquidity that allows for continuous trade.

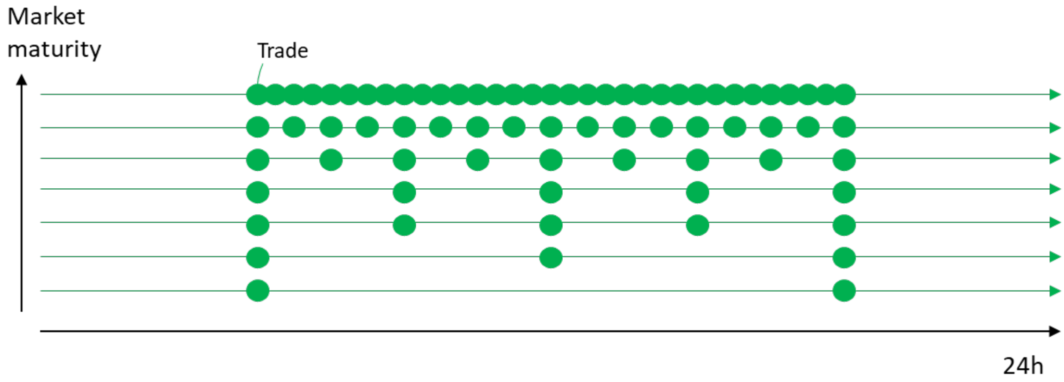

Figure 29: Market maturity and frequency of auctions

From the perspective of the DSO, continuous trade is likely an ideal market solution under the provision that it is able to provide an effective market clearing. This is assumed due to the constant availability of flexibility resources. The more realistic and, in this setting, also effective market solution may however be one based on discrete auctions. The reason is that a local market may have troubles gathering enough participants and thus liquidity to be able to support continuous trade. For reference, the Swedish intraday market is based on continuous trade and sometimes face efficiency problems due to low liquidity.

2.4 Pros and cons of DSM and DR for different resources

As explained in section 2.1 of this sub-chapter, a DSM solution allows the DSO to directly control the flexibility asset for operational network security purposes while a DR solution is only available after a case-by-case trade agreement is in place. A typical DSM asset may for example be a single heat pump while a typical DR asset may be multiple EV chargers managed by an aggregator. Note that DSM and/or DR are applicable to all flexibility resources. In this section potential pros and cons of the different solutions are discussed for broad groups of flexibility resources. Further research is needed within this field. *Equipment in the grid* is not covered in this section as these are inhouse services and therefore not applicable for DSM or DR.

2.4.1 Large scale generation

Large generating units such as wind parks may be better suited for a DR solution rather than a DSM solution. One reason is potential issues regarding the balance responsibility. This example is simplified and based on current Swedish regulation. Before the hour of delivery, the expected production from the unit is estimated and traded on the electricity markets aiming for balance during the delivery hour meaning that the sold volume equals the produced volume. The BRP (which may or may not be the owner of the generating unit) reports the production plan to the TSO 45 minutes prior to the start of the delivery hour. [31] If production is curtailed during the delivery hour the reported and actual production will differ. The balance settlement is calculated per bidding area [31] which may be larger than the area captured by the local market and the curtailment may therefore have resulted in an unintended imbalance and subsequent charge to the BRP.

While it is difficult to achieve perfect balance due to many other reasons than potential curtailment, it is problematic if a BRP would find itself in imbalance and subsequently subject to a charge due to a unit in its portfolio being curtailed by a third party. Especially since the curtailment likely solved a local network issue.

Applying a DR solution to large generating units would regain the control to the owner of the resource and the BRP. It may be possible to, in real time, adjust for the curtailment thereby avoiding imbalance.

This potential issue is further investigated in Chapter 4.

2.4.2 Small scale generation

Small generating units such as residential PVs may be suitable for either a DSM or DR solution. It is likely to depend on either the interest of the owners of the resource or on how they choose to engage their flexibility resource on the market.

The owners may be interested in participating on the flexibility market themselves. The best solution is then given by their individual preferences. However, they may not be interested in active participation. If that is the case and they do not engage with an aggregator, the DSM solution is likely more suitable than the DR solution, minimising the effort. If they do engage with an aggregator, the DR solution may be more suitable than the DSM solution given that it is more dynamic, and the aggregator has resources to actively participate with large volumes on the market.

2.4.3 Large scale loads

Large scale loads are found at for example property owners using large amounts of electricity on functions such as heating and cooling. Similarly to owners of large scale generation, it is likely that owners of large scale loads are unwilling to hand over control to the DSO. Heating costs for Swedish apartment buildings is on average 30 percent of total operating costs and 20 percent of total costs, meaning that it is a significant cost item. [32] While this makes it attractive to offer flexibility to the DSO, it is also high risk and the provider must be able to trust that for example indoor temperatures are within acceptable intervals.

With sufficient control equipment, sensitive parameters will be automatically controlled for, and the DSO and the property owner will be able to act according to these parameters. This can for example allow for a DSM solution with a dynamic price mechanism as one of the steering parameters. However, if it is not possible to incorporate relevant parameters a DR solution may be better suited.

2.4.4 Small scale loads

When utilising a load as a flexibility resource its contribution is often to advance or delay power use. It may therefore be suitable for a DSM solution as the total consumption over time is unaffected, and the owner of the flexibility resource owner is unlikely to notice that the flexibility resource is being utilised unless informed. Unlike the large scale load owner the small scale load owner is usually only responsible for its own personal convenience. The main cost to take into consideration is any adverse effects on the convenience for the owner/relevant stakeholders, such as residents in a house with a heat pump being utilised as a flexibility resource, and this is easily captured and regulated by a long-term contract.

3 OVERVIEW OF CHARACTERISATION

This chapter provides an overview of the flexibility resources described in this report under sub-chapter 1. All flexibility resources have a low enough response time, below minutes that are considered to be needed for the applications addressed within the ANM4L project.

Table 7: Flexibility characterisation

Resource	Owner	Provides	Availability / reliability	Utilization cost	DSM/DR
Wind Park (Large scale generation)	Company	Active power	• Depends on the wind conditions • Can only increase the active power if already running in curtailed mode	• Reduction of revenue for owner • Cost of mechanical wear and tear, for curtailment and for shutdown	DR
Wind Park (Large scale generation)	Company	Reactive power	• Always available if connected to the grid	• Potential reduction of revenue for owner due to reduced production of active power	DR
PV (Large scale generation)	Company	Active power	• Depends on the solar radiation • Can only increase the active power if already running in curtailed mode	• Reduction of revenue for owner • Potential mechanical wear and tear of the inverter	DR
PV (Large scale generation)	Company	Reactive power	• Always available if connected to the grid	• Potential reduction of revenue for owner due to reduced production of active power	DR
PV (Small scale generation)	Private / Aggregator/ Company	Active power	• Depends on the solar radiation • Can only increase the active power if already running in curtailed mode	• Reduction of revenue for owner	DSM/DR
PV (Small scale generation)	Private / Aggregator/ Company	Reactive power	• Control equipment for reactive power must be installed • Always available if connected to the grid	• Potential reduction of revenue for owner due to reduced production of active power	DSM/DR
Heat pumps (Residential load)	Private / Aggregator / Company	Active power, Shifting power in time	• Depending on the outdoor temperature and insulation value for the building • Only impact on indoor climate as defined in the agreement • Consider rebound of power	• Low impact on total energy use • Cost of inconvenience for the owner need to be considered	DSM/DR
EV charger (Load)	Private / Aggregator / Company	Active power, Shifting power in time	• Depending on the use of the cars and if connected to the charger • Can only increase the power consumption if battery is not already fully charged	• No impact on the total energy use • Cost of inconvenience for the owner need to be considered	DSM/DR
Tap changer	DSO	Voltage control	• Depending on the rating and current position of tap changer	• Mechanical wear and tear	-
DLR	DSO	Enables flexibility through increased capacity	• DLR is always available but its output depends on external factors such as temperature and wind	• No direct cost to supply flexibility	-
Reactive power compensation equipment (Capacitor bank, STATCOM, etc)	DSO	Reactive power	• Depending on the rating and current level of activation	• Mechanical wear and tear	-

4 DISCUSSION

In this chapter, different flexibility resources relevant for the Swedish and Hungarian demo cases of the ANM4L project, are characterised. They are divided into four different categories:

- Generation
- Load
- Equipment in the grid
- Flexibility enabler

As part of the characterization process, costs for utilising the different resources are identified. These are listed in Table 7 in the previous sub-chapter and described in sub-chapter 1. While different cost types are identified, the task of quantifying each cost for each resource is challenging. However, although it is difficult to exactly quantify each cost, it is possible to argue that some may be negligible while others may be major.

Costs that, on the one hand, may be negligible under certain circumstances include shift of power consumption in time, and in some cases cost of inconvenience.

For small scale loads in Sweden shifting power consumption in time is expected to rarely lead to increased (or decreased) electricity costs. For these consumers, the most common electricity rate is a fixed monthly rate, meaning that the cost of consuming electricity is the same at all times during one month. There are three exceptions to when shifting power consumption to another time may lead to changed electricity costs.

- The first is if consumption is shifted from one month to another. The rates are likely to differ between months and if the rate of the second month is higher, the electricity costs will be higher compared to if consumption was left unchanged, however, if the rate of the second month is lower the electricity costs will instead be lower compared to if consumption was left unchanged.
- The second is if there are any rebound of power. There may be a rebound of power if a load is turned off or reduced and later turned back on or returned to normal operation. The load might need more power after than before it was utilised as a flexibility resource.
- The third is if it is more energy (and therefore also cost) efficient to maintain electricity consumption compared to temporarily increasing or decreasing consumption.

As described, the use of some flexibility resources may affect the comfort of consumers in their home and daily lives. The cost of inconvenience is likely to depend on how much consumers are affected, and in some cases it may be insignificant. For example, it is assumed that the cost of inconvenience for utilising a heat pump as a flexibility resource is limited as long as limits concerning indoor temperature etc. are respected, however not that if temperatures vary significantly or outside agreed limitations the cost is expected to be substantial. Much research has been done on consumer willingness to participate in flexibility markets and the importance of different aspects such as (in)convenience, remuneration/savings vs. environmental motivations, see for example Ref. [33] and [34].

Costs that, on the other hand, may be major are reduction of revenue for owners due to curtailment of renewable energy sources, and potentially also penalties for not delivering as promised. The latter can for example refer to power purchase agreements or unmet production plans. In addition, there are other factors such as environmental aspects to consider when contemplating curtailment of renewable energy sources.

Curtailing renewable energy sources means spilling available renewable power and, unless storage is available, it is not possible to shift consumption of spilled power to another time. Therefore, curtailment should always be the last option.

CHAPTER 4: REGULATORY REVIEW AND IMPLICATIONS

(ANM4L DELIVERABLE D4.3)

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1 INTRODUCTION

This chapter provides a review of relevant regulation in the Directive on common rules for the internal market for electricity (EU) 2019/944 (which upon launch of the Clean energy for all Europeans package replaced Electricity Directive (2009/72/EC)), and the Regulation on the internal market for electricity (EU) 2019/943 (which upon launch of the Clean energy for all Europeans package replaced the Electricity Regulation (EC/714/2009)) combined with a brief overview of related national regulation in Sweden ang Hungary. In addition, relevant methods of economic regulation for distribution system operators are reviewed. The report investigates how relevant parts of the above-mentioned regulations may have an impact on the implementation of ANM solutions in distribution networks.

The Clean energy for all Europeans package was launched in 2016 and implemented in 2019. The package consists of a new set of rules to ensure continued transition and reach the goals stipulated in the Paris Climate Agreement from 2015, i.e., a minimum 40 percent reduction of greenhouse gas emissions by 2030. The package was implemented when the Council of ministers of the EU formally approved the last four out of eight new legislations thereby future proofing the European electricity market. [35] [36]

Member states are continuously working on implementing the new directives and regulations in national law. When possible and if relevant, this report covers both current and future national regulation. Additionally, any relevant national regulation that does not stem from EU regulation is covered in this report.

2 BACKGROUND

The energy system is currently undergoing a radical transformation minimising greenhouse gas emissions and maximising the share of renewable energy sources (RES) in the energy mix. The electricity market is a key enabler of this transformation, creating new opportunities and challenges for market participants while recent technological development provides opportunities for active consumer participation.

The recent technical developments have allowed RES to be economically viable. This has resulted in a paradigm shift forcing the traditionally one-directional distribution grids to be utilised in a bi-directional manner with an increased amount of distributed generation (DG). [28]

The main challenge with this transformation is managing intermittent electricity generation by weather dependent sources such as wind and solar that are not adaptable to demand, [37] and often located at the edge of the grid. Grids are commonly structured similarly to a spiderweb, adapted to centralised generation with heavy lines close to the generation facilities and lighter lines further out. Fluctuations caused by intermittent generation in the periphery can therefore have a larger impact on the grid compared to if the intermittent generation facility had been placed at the centre. [28]

Distribution system operators (DSOs) are monopolists and therefore heavily regulated to protect consumers. There are multiple approaches for the DSOs to manage the issues brought by the increasing share of RES, many of which are dependent on the regulatory landscape within which they operate. The European Commission is continuously working on adapting relevant regulation to correspond to current and future conditions. Both Hungary and Sweden are member states of the European Union and therefore national laws and regulations are heavily influenced by EU regulation.

The Clean energy for all Europeans package addressed all pillars of the Energy Union[3]. It was launched in 2016 and implemented in 2019. The package consists of a new set of rules to ensure continued transition and reach the goals stipulated in

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[3] The European Energy Union is a strategy founded by the Juncker Commission in 2015. Its purpose is to strengthen the European energy security, sustainability, and competitiveness through five pillars: Energy security, solidarity and trust; A fully integrated European energy market; Energy efficiency contributing to moderation of demand; Decarbonising the economy; and Research, Innovation and Competitiveness. [69] Since 2015, the Commission and its member states have worked on achieving the strategy through implementing different packages and following up on 27 National Energy and Climate Plans (NECPs). [70] A key objective of the Energy Union is to not leave any citizens or regions behind. All consumers, including vulnerable and energy poor, should be able to reap its benefits. [68]

the Paris Climate Agreement from 2015, i.e., a minimum 40 percent reduction of greenhouse gas emission by 2030. [35]

The package was implemented when the Council of ministers of the EU formally approved the last four out of eight new legislations, thereby future proofing the European electricity market. [35]

The four legislations implemented in 2019 are the Directive on common rules for the internal market for electricity (EU) 2019/944 (replaces Electricity Directive (2009/72/EC)), the Regulation on the internal market for electricity (EU) 2019/943 (replaces the Electricity Regulation (EC/714/2009)), the Regulation on risk preparedness in the electricity sector (EU) 2019/941, and the Regulation (EU) 2019/942 establishing a EU Agency for the cooperation of energy regulators (ACER) (replaces regulation 713/2009). [38]

Note that some of these legislations are directives while some are regulations. While an EU regulation applies in in all member states regardless of national laws and regulations, an EU directive is a set of rules that sets objectives to be achieved but leaves it to the Member States to formulate their own detailed national laws and regulations.

Designing and implementing efficient regulation is challenging. This chapter focuses on existing[4] and (when possible) future regulations in Sweden and Hungary and how the regulatory framework, especially the income regulation, shape DSO behaviour.

2.1 Available options to manage grid issues

As described in multiple reports published as part of the ANM4L project the available tools and resources to manage voltage levels and avoid overload situations and allow for more generation from intermittent RES can be categorised into four different groups (see Chapter 4):

- Generation control;
- Flexible consumers;
- Equipment in the grid, and
- Flexibility enablers.

In addition, the DSO can also reinforce or expand the grid.

[4] As per 2021

If the DSO procures flexibility from an external party (e.g., using generation control or flexible consumers), a specific mechanism or market may be necessary to facilitate trade.

3 REGULATIONS ENABLING ANM SOLUTIONS

Swedish and Hungarian regulations are heavily influenced by EU regulation. EU directives are transposed into EU member states national law, which directly influence how the electricity market function, including roles and responsibilities of its actors. Electricity network owners and operators, given their position as monopolistic providers of electricity transmission and distribution services, are particularly influenced since the legal framework, through the national electricity network regulations, determines the level of their revenue. The following sections reviews the EU directives and regulations relevant for enabling ANM solutions. First, properties of electricity network economic regulation are outlined and discussed, which is then followed by a review of recent EU regulations and the impact on Hungarian and Swedish national law. The aspects of EU regulations are grouped into three categories:

- *Regulation enabling ANM* solutions aims to capture regulations that aim at setting up a landscape suitable for these kinds of solutions before they are implemented;
- Regulation enabling participation aims to capture regulations that aim at enabling participation of different actors, and
- Operational regulation aims to capture regulations that aim to regulate the solution itself, how it is used and to solve new operational issues.

3.1 Economic regulation of electricity networks

During the 1980s and 1990s many countries unbundled (removed vertical integration between the different segments) and privatised much of their electricity sectors. The move to reduce the state involvement in the generation, transportation and supply of electricity was driven by both political agendas and principles from the field of economics of prospective efficiency gains through competition. Electricity networks are capital intensive, creating high economies of scale and thus high barriers to entry for new actors. As a result, electricity networks, transmission and distribution of electricity, are considered to be natural monopolies. This means that it is more efficient (less costly) to only allow one company to own and operate the electricity network within a defined area rather than to open up to many companies and competition.

However, the concentration of market power to one or more actors is generally associated with inefficient practices such as excessive pricing and lack of innovation and technological advancement. Therefore, as natural monopolies, DSOs and TSOs are subject to economic regulation to prevent monopoly pricing, discriminatory network access and to ensure sufficient investment and maintenance for a safe and efficient level of supply [39] [40].

Since privatisation, the general objective of regulation, in addition to stringent security requirements, has focused on improved efficiency in the operation and maintenance of networks. This is achieved through improved short-run efficiency (making the best use of existing resources) and long-run efficiency (appropriate long-run investments). National regulatory authorities (regulators) have an informational disadvantage in terms of the operational environment, technical specifications, costs and behaviour of the firms that they regulate. This means that network companies may be able to abuse its monopolistic position to its advantage. For example, by overstating its costs or reducing spending leading to poor managerial efforts, in order to maximise its own profits. Abuse of a monopolistic position would come at a cost to electricity consumers and reduce overall social welfare.

Traditionally there are two main types of regulatory frameworks applied to network companies to overcome issues related to information asymmetry; price cap regulation and cost of service regulation. In price cap regulation, the regulator determines a price cap or fixed price for distributed energy. Whilst consumers are protected against monopoly pricing or unexpected increases, the network company and its managers are motivated to first exaggerate its costs to the regulator and then, through operational advances, reduce its actual costs without the requirement to share any savings with consumers. The gains from costs reductions, which may reduce quality of supply, will thus remain solely with the network company. Meanwhile, in a cost of service framework the regulator agrees to compensate network companies for a certain level of service. Provided that the regulator is able to accurately audit costs, the network company will be reimbursed fully for its true production costs and the company will not have an incentive to exaggerate its costs. Consumers would share potential benefits of cost reductions, however, the network companies have no incentive to innovate or develop procedures to reduce costs as this would lower its overall compensation since only realised costs will be reimbursed.

As a result of the difficulties in encouraging truthful reporting and behaviour from regulated companies, regulators have often applied a combination of price cap and cost of service regulation. Many also rely on benchmarking of network companies' costs and productivity to determine the overall allowed revenue. Benchmarking of companies' performance reduces the informational gap between regulated companies and the regulator and it encourages performance improvements. Regulatory methods that incentivise certain behaviour and efficiency improvements are typically referred to as incentive regulation. The regulatory frameworks for Hungary and Sweden [7] are outlined, below.

The Swedish electricity grid is divided into three different levels; the high-voltage transmission network, owned and operated by the state-owned TSO, the medium-voltage regional distribution network, owned and operated by 18 regional DSOs, and the low-voltage local distribution network, owned and operated by 152 local DSOs. The 170 DSOs vary in size, operational environment, and ownership structure, including state, municipal, and privately-owned. The Swedish Energy Markets Inspectorate, the regulator in Sweden, work on assignment from the government to ensure a well-functioning energy sector, safe and secure supply of energy, and to support energy consumers interests. Included in this work the economic regulation of networks. Since 2012, the regulator applies an ex-ante revenue cap to both the transmission and distribution networks. The network companies propose the TOTEX (total expenditure) (divided into CAPEX (capital expenditure), non-controllable OPEX (operating expenditure) and controllable OPEX) to be used to determine the revenue cap, which is assessed and finally set by the regulator for a four-year period. The revenue cap is set to cover operational costs and a reasonable return on capital. The depreciation of assets follows a straight-line method dependent on expected economic life and vary between different types of assets. There are 17 different asset categories and six different depreciation times, varying between 10 and 50 years. The regulator also applies incentives to improve efficiency of controllable OPEX, determined through a benchmarking exercise, and to improve quality of supply. An overview of the Swedish revenue cap and its different building-blocks are depicted in Figure 30, below.

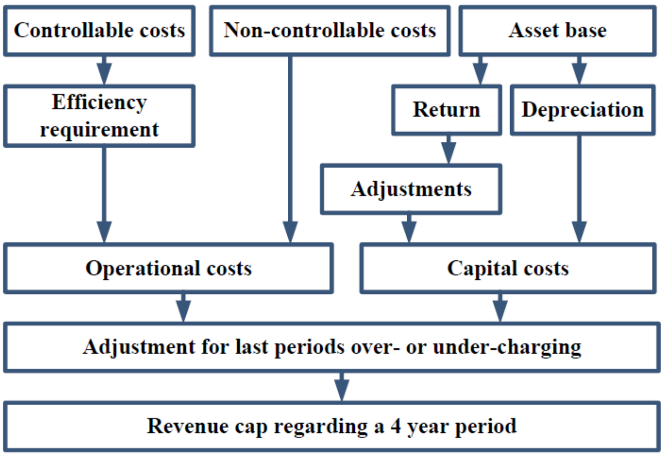

Figure 30 - Overview of the Swedish revenue cap [41]

The Hungarian electricity grid is made up of one TSO, which is publicly owned, and six DSOs, of which one is publicly owned and five that are privately owned companies. The Hungarian Energy and Public Utility Regulatory Authority (HEA) oversee the market and the electricity networks are regulated by a hybrid model where a revenue cap is set ex-ante in a price-cap-like system (i.e., the revenue cap is determined by price/tariffs multiplied by the quantity of distributed energy). The regulator performs a cost review for each network company and the justified costs (OPEX, CAPEX, depreciation and network losses) are calculated and included in the revenue cap together with the distributed energy. An efficiency incentive is applied to OPEX, determined through a benchmarking exercise, and an incentive for improved quality of supply is applied through a bonus/penalty system based on the quality of supply in the previous regulatory period. Depreciation follows a straight-line method and is determined based on expected economic life of the different types of assets, with the annual rate varying between 2.5% and 7%.

Similar to Hungary and Sweden, many European regulators apply incentive regulation to electricity network companies to encourage firms to become more efficient, increase investments, and to make sure that consumers benefit from cost reductions. Incentives generally come in the form of financial rewards or penalties but can also consist of other schemes, for example reputational incentives. A range of incentives allows regulators to increase their focus from mainly considering safety requirements and efficiency improvements to include other aspects that can contribute towards meeting wider policy objectives, including those related to climate change goals and the energy transition. For example, recent developments have seen an increased focus on network customers' objectives through the introduction of incentives to improve quality of supply, a feature in most European regulatory frameworks, and active customer engagement, implemented by the Great Britain regulator Ofgem.

It is also possible to introduce incentives to encourage DSOs to look beyond traditional network expansions, and apply ANM solutions and other measures, in order to increase network capacity. For example, to promote energy efficiency, lower network losses and reward peak-shaving, the Swedish regulator recently introduced an incentive to encourage efficient utilisation of network [41]. The incentive should support the development of new and innovative processes, including operation and maintenance, which can delay investment in and expansion of the grid. However, the fundamental framework remains the same.

Both Hungary and Sweden apply revenue cap regulation following a similar general building-block principle where allowed revenue is made up of $OPEX + depreciation + asset\ base \times WACC$. OPEX and CAPEX are treated differently – OPEX is remunerated within the period they occur whilst CAPEX is added to the asset base and reimbursed over time through depreciation and an allowed return on the invested capital. By investing in assets, DSOs will grow its asset base and therefore its guaranteed return for many years. Different types of assets have different expected economic life and therefore depreciation ratios. Assets such as cables and lines have a long expected economic life, typically 40-60 years, whilst IT infrastructure and equipment in the grid may have about 10 years expected economic life. This means that DSOs will maximise its expected return by investing in large infrastructure that depreciate over a longer time and that they therefore may be more willing to invest in network expansion than an ANM solution.

There is a level of substitutability between CAPEX and OPEX and depending on the objectives of the regulator this could be utilised. However, a balance must be established to avoid potential OPEX-bias, leading to short-term operational focus, and CAPEX-bias, leading to long-term over-investments and overengineering. Moreover, OPEX is benchmarked against other DSOs and an efficiency incentive is applied. Benchmarking and establishing efficiency requirements on CAPEX is generally considered challenging due to the nature of capital investments, which vary greatly between different years and different DSOs. As a result, the efficiency requirement imposed on OPEX, in addition to the guaranteed long-term return on CAPEX, may lead DSOs to prioritise CAPEX expenditure, i.e., induce CAPEX-bias, particularly in assets with long expected economic life, over OPEX expenditure.

The current regulatory framework is fit for the traditional DSO role, i.e., the passive transporter of electricity with no need to consider bi-directional electricity flow or prosumers. However, with changing circumstances, new actors, roles, responsibilities, and objectives, the economic regulation will need to be updated to encourage and allow DSOs to take on a more active role and to find and implement alternative solutions to traditional network expansion. It is possible that updates would have to go beyond introducing additional incentives to the current framework, a more fundamental review may be required. The regulatory framework for DSOs could possibly be adjusted to become more similar to the framework applied to TSOs, with more clearly defined incentives for the efficient and economic operation of the system, including separate allowances for acquiring balancing services.

Furthermore, a possible solution to overcome potential CAPEX-bias is changing from a system that treats CAPEX and OPEX differently to a system where all costs are treated in a similar manner, so called TOTEX-regulation [42]. Reducing the distinction between OPEX and CAPEX and adapting the tools that determine efficiency could allow regulators to change the way DSOs are regulated, as a result of new economic objectives, roles, and responsibilities. Changing the efficiency requirement to include DSOs' total costs, rather than only controllable OPEX, is a recent proposal from the Swedish regulator. An example of the suggested framework is illustrated in Figure 31, below.

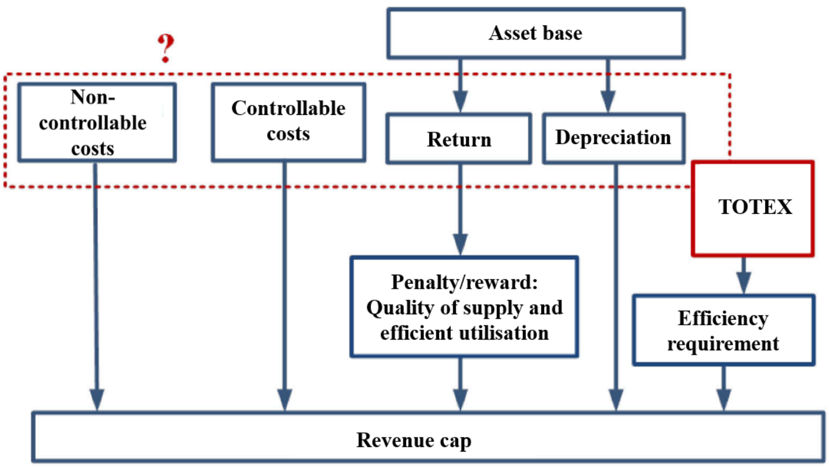

Figure 31 - Alternative Swedish revenue cap with efficiency requirement applied to TOTEX (adapted from [43])

3.2 EU regulation

3.2.1 Smart metering systems

A smart meter is a device that records and communicates information such as electricity consumption and voltage levels and therefore allows consumers to actively monitor and adapt their actual consumption and/or allow for a third party to do so. It is a necessary tool for consumers who wish to actively engage on the electricity market and/or in some other way offer flexibility services to the DSO.

Articles 19, 20 and 21 of EU directive 2019/944 states that member states should, if/when deemed economically beneficial based on a cost-benefit assessment (CBA), ensure that smart metering systems are introduced to support active participation of consumers in the electricity market. Consumers are however entitled to a smart metering system even if the CBA assess a system wide deployment to be unprofitable but then at their own cost.

The functionality requirements are in short that the smart metering system should be able to provide final consumers with information on actual time of use as well as validated historical consumption. Information should be free, easily available, and secure. Upon request of a consumer the system should be able to handle and account for electricity fed into the grid. The information provided to the consumer should be easy to understand and allow the consumer to compare offers. A third party should be able to act on behalf of the consumer, among other things this entails that the consumer should be able to relay information to the third party (see chapter 3.2.3). Regarding pricing, the smart metering system should allow consumers to be settled at the same time resolution as the national settlement period.

In 2018, the Swedish government decided to deploy "the next generation" of smart meters in Sweden. The work has commenced and is due to be completed before 2025. A CBA concluded in 2015 that deployment of smart meters would be beneficial. The smart meters will be able to measure hours and have a user interface that makes it possible for customers to read their own consumption data. They will make it possible for consumers to actively engage on the electricity market and at the same time allow for a safer operation of the grid. [44]

For Hungary, the results of the first and second CBA however show inconclusive results and the results from a third CBA conducted in 2018 were in 2020 still under review[5]. Some DSOs are working on smart metering deployment (mainly in relation to pilot projects), however there is no large-scale rollout underway. [45] Because the CBAs have been inconclusive there are no requirements for a large-scale rollout, but the CBA must be repeated every fourth year or more often. [46]

[5] The authors of this report have not been able to find any more recent information.

While smart meters in households are not necessary for all ANM solutions, the available solutions are limited in their absence. The possibility to engage consumers on the electricity market is for example not available. However, other types of technologies may be just as important in an ANM solution and the discussion of smart meters is changing into also including a more integrated use of information and communication technology (ICT) and digitisation. Such technology can be, for example, smart household appliances (such as heat pumps) that in an ANM setting can allow network owners to remotely adjust loads by communicating directly with the appliance rather than with the consumer.

3.2.2 Information

As previously mentioned, some ANM solutions involve a third party or an active consumer that need access to information. The EU directive 2019/944 therefore stipulates in article 31 that the DSO must be willing and able to provide system users with information needed for efficient access to and use of the system.

The Swedish regulator interpret this article mainly in term of fees and conditions for transmission of electricity. This is regulated in the Electricity Act. Chapter 4, paragraph 11, states that a grid owner swiftly should hand out information on fees and conditions. [47] It is however unclear if the information referred to include all necessary information for an active consumer or an aggregator. The Hungarian Electricity Act states in section 24 that information should be shared to any eligible party subject to consent of the customer without any discrimination.

Closely related to the above-mentioned technologies, information, and ANM solutions in general is cybersecurity which is generally discussed throughout directive 944/2019.[6] As stated in article 20, "the security of the smart metering systems and data communication shall comply with relevant Union security rules, having due regard of the best available techniques for ensuring the highest level of cybersecurity protection while bearing in mind the costs and the principle of proportionality". For grid owners working with ANM solutions it is important that measures to ensure security are being taken already when the solutions are beginning to be implemented. Furthermore, different actors involved with the same or interlinked systems would benefit from common standards.

3.2.3 Third party access

Third party access is usually regulated for industries with natural monopolies such as operators of electricity grids and other vital infrastructures that cannot be economically duplicated. The motivation for this regulation is to uphold competition in the provision of a service or product closely related and often dependent on the natural monopoly. Absent third party access regulation, there is a risk of monopolists abusing their power by for example hindering third party access using

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[6] See paragraph 57, article 20, article 40 and Annex II.

measures such as unjustifiable high tariffs or discriminatory terms and conditions. A third party can for example be an aggregator in need of accessing smart meters out in the grid.

EU directive 2019/944 article 6 regulates third party access and states that each member state must ensure that it is based on publicly available tariffs applicable to all customers and applied objectively and without discrimination between system users. Access can however be denied due to lack of necessary capacity. But in contrast to previous regulation, grid owners must now provide relevant information on what measures would be required to strengthen the network and thus allow for new connections. Furthermore, the article has (compared to previous regulation) been expanded to also apply to citizen energy communities that manage distribution networks.

Swedish regulations are in general well adapted to meet the requirements stated in the above article, see ref. [47]. No regulation currently applies to citizen energy communities. However, that should not have an impact on grid owners' ability to utilise ANM solutions. Also, Hungarian regulation, Electricity Act section 142, states that use of the electricity system and network access fees should be transparent, publicly available and proportionate, and applied objectively in a non-discriminatory manner. In contrast to Swedish legislation, section 66/B in the Electricity Act regulates energy communities and recognises that they may be involved in generation, storage, consumption of electricity, flexibility services, electricity sharing, aggregation, electro-mobility services and charging services for electric vehicles.

3.2.4 Energy storage

Energy storage is a key component to ANM solutions. As lithium-ion battery prices continue to decrease energy storage becomes an increasingly affordable tool. [48] Battery energy storage systems (BESS) can support grid owners with reactive power compensation, management of peak loads, and other DSO level services. As with all ANM solutions, this may reduce future grid reinforcement needs.

Despite its benefits and affordability, EU regulation (Article 36 in 944/2019) prevents grid owners to own, develop, manage, and operate energy storage facilities. There are reasons for this regulation. DSOs are heavily regulated monopolies and therefore not allowed to participate in unregulated electricity markets. As BESS could be used to provide services in the electricity and balancing markets the fundamental rule is therefore to not allow DSOs to own, develop, manage, and operate energy storage facilities. Furthermore, BESS may be owned and operated by producers of electricity. They would, in contrast to the DSO, be allowed to sell stored electricity on electricity markets thereby increasing its usage potential as the DSO simultaneously can utilise the resource as an ANM service by procuring it from the producer.

Article 36 in 944/2019 allows for member states to make exceptions and allow DSOs to own and operate BESS in two occasions; first, if such a facility is necessary for the grid owner to fulfil their obligation, that they will not be used to participate on any electricity market and the facilities are entirely integrated grid components, and second, if an open, transparent, and non-discriminatory tendering procedure, that was reviewed, approved, and deemed necessary by the regulating authority, was unsuccessful in acquiring the required services from a third-party. Tendering procedures vary between countries and each the regulatory authority of each country may provide guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure. In Sweden, the procurement tendering process for companies supplying utilities such as network owners is regulated by law (2016:1146).

While Swedish regulators have allowed for grid owners to own, develop, manage, and operate energy storage facilities as part of their grid operations, they have not been allowed to use the storage facility to participate on the market, for example to sell stored electricity. The current Swedish regulation is less strict than the new EU regulation and it is therefore likely to be updated and only allow grid owners to own energy storage facilities under the above mentioned exceptions. [49]

Hungarian regulators allow DSOs to own energy storage facilities. According to Section 33/C of the Electricity Act a DSO may install and operate an electricity storage facility if it complies with the lowest possible cost principle. The facility should be incorporated into the distribution network to ensure the secure and reliable operation of the distribution system although not used for congestion management. Furthermore, it must not exceed a nominal output capacity of 0.5 MW. The current Hungarian regulation is likely to change within the near future, however the exact formulation is unknown.

4 REGULATIONS ENABLING PARTICIPATION

4.1 Active customers

Many flexibility resources are located in households and the owner of each resource must take an active decision to provide the local DSO with flexibility. The EU definition of an active customer is, according to point 8 in article 2 in 2019/944 "… a final customer, or a group of jointly acting final customers, who consumes or stores electricity generated within its premises located within confined boundaries or, where permitted by a Member State, within other premises, or who sells self-generated electricity or participates in flexibility or energy efficiency schemes, provided that those activities do not constitute its primary commercial or professional activity".

The rights and obligations of active consumers are regulated in article 15 in 2019/944, see box 1 below. While the requirement of being "financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943" likely is challenging for the lone consumer the regulation otherwise does not hinder household participation in ANM services, and much of the technical and administrative burdens can be alleviated by an aggregator or citizen energy community, see chapter 4.2 and 4.3 below. The challenges related to household participation are probably more about incentives and knowledge than regulation, see chapter 0.

According to the Swedish Electricity Act (3 chapter, 16a §§) DSOs are not allowed to set technical requirements that make it difficult for consumers or other actors to provide flexibility services or in any other way hinder their participation. However, they are allowed to set requirements to ensure a safe, reliable, and efficient operation of the electricity network. See more on technical requirements in chapter 6.1 below. Similar regulations apply in Hungary where the DSO is required to treat all actors equally, thereby they may not hinder any actors' participation due to too advanced technical requirements. However, there are no regulations specifically on active customers as of yet.

BOX 1: ARTICLE 15, EU 2019/944 – ACTIVE CONSUMERS

1. Member States shall ensure that final customers are entitled to act as active customers without being subject to disproportionate or discriminatory technical requirements, administrative requirements, procedures and charges, and to network charges that are not cost-reflective.

2. Member States shall ensure that active customers are: (a) entitled to operate either directly or through aggregation; (b) entitled to sell self-generated electricity, including through power purchase agreements; c) entitled to participate in flexibility schemes and energy efficiency schemes; (d) entitled to delegate to a third party the management of the installations required for their activities, including installation, operation, data handling and maintenance, without that third party being considered to be an active customer; (e) subject to cost-reflective, transparent and non-discriminatory network charges that account separately for the electricity fed into the grid and the electricity consumed from the grid, in accordance with Article 59(9) of this Directive and Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system; (f) financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943.

3. Member States may have different provisions applicable to individual and jointly-acting active customers in their national law, provided that all rights and obligations under this Article apply to all active customers. Any difference in the treatment of jointly-acting active customers shall be proportionate and duly justified.

4. Member States that have existing schemes that do not account separately for the electricity fed into the grid and the electricity consumed from the grid, shall not grant new rights under such schemes after 31 December 2023. In any event, customers subject to existing schemes shall have the possibility at any time to opt for a new scheme that accounts separately for the electricity fed into the grid and the electricity consumed from the grid as the basis for calculating network charges.

5. Member States shall ensure that active customers that own an energy storage facility: (a) have the right to a grid connection within a reasonable time after the request, provided that all necessary conditions, such as balancing responsibility and adequate metering, are fulfilled; (b) are not subject to any double charges, including network charges, for stored electricity remaining within their premises or when providing flexibility services to system operators; (c) are not subject to disproportionate licensing requirements or fees; (d) are allowed to provide several services simultaneously, if technically feasible.

4.2 Aggregators

Aggregators are frequently discussed, and many find it likely that this type of actor will play an important role on the future energy market. Just as the name imply, an aggregator can gather actors and sell their aggregated flexibility to a DSO or to other consumers. From the perspective of the DSO, this is a convenient solution as they only need to establish a contract and relationship with the aggregator, instead of each actor.

For DSOs looking to implement demand response or load control as an ANM solution, an aggregator is likely to simplify the relationship between the DSO and the consumer/prosumer and minimise the administrative burden. Furthermore, by representing the consumer/prosumer the aggregator can contribute with a more even distribution of knowledge between buyer and supplier.

Article 13 regulates consumers and prosumers right to enter and exit contracts with aggregators and article 17 in 2019/944 states that each Member State has a responsibility to "allow and foster participation of demand response through aggregation" and that system operators (TSO and DSO) treat actors that offer ancillary services such as flexibility via aggregation of demand response equal to other producers regardless technical capabilities.

The new articles specifically addressing aggregators have not yet been implemented in Swedish legislation. [49] In February 2020, NordREG, the organisation for Nordic energy regulators, published a report with recommendations on a common Nordic regulatory framework for independent aggregators. To allow for cross-border cooperation they propose to develop a harmonised regulation for all Nordic countries. [50] The Swedish Energy Markets Inspectorate will propose a suggestion for regulation of aggregators that will ensure alignment with the regulation of bordering nations and that DSOs and TSOs treat their services equal to those of similar market actors. The addition of aggregators in national legislation is likely to only increase the possibilities for DSOs to utilise local flexibility resources.

Hungarian regulators have incorporated aggregators throughout the Electricity Act and, from a regulatory perspective, they are allowed to engage consumers and other actors to deliver aggregated flexibility services to DSOs.

4.3 Citizen energy communities

Article 16 in 2019/944 regulates citizen energy communities. The definition of a citizen energy community is, according to point 11 in article 2 in 2019/944, defined as "(…) a legal entity that,

- is based on voluntary and open participation and is effectively controlled by members or shareholders that are natural persons, local authorities, including municipalities, or small enterprises;
- has for its primary purpose to provide environmental, economic or social community benefits to its members or shareholders or to the local areas where it operates rather than to generate financial profits; and
- may engage in generation, including from renewable sources, distribution, supply, consumption, aggregation, energy storage, energy efficiency services or charging services for electric vehicles or provide other energy services to its members or shareholders."

Citizen energy communities are of high relevance for ANM solutions involving consumers and/or prosumers, especially demand response. Like aggregators, they may be a way of aggregating multiple flexibility resources and efficiently facilitate the relationship between consumers and grid owners. Citizen energy communities may function as a non-profit aggregator with the purpose of providing environmental, economic or social community benefits, in this case by offering large amounts of flexibility within a clearly defined framework that all members of the community accept.

BOX 2: ARTICLE 16, EU 2019/944 – CITIZEN ENERGY COMMUNITIES

1. Member States shall provide an enabling regulatory framework for citizen energy communities ensuring that: (a) participation in a citizen energy community is open and voluntary; (b) members or shareholders of a citizen energy community are entitled to leave the community, in which case Article 12 applies; (c) members or shareholders of a citizen energy community do not lose their rights and obligations as household customers or active customers; (d) subject to fair compensation as assessed by the regulatory authority, relevant distribution system operators cooperate with citizen energy communities to facilitate electricity transfers within citizen energy communities; (e) citizen energy communities are subject to non-discriminatory, fair, proportionate and transparent procedures and charges, including with respect to registration and licensing, and to transparent, non-discriminatory and cost-reflective network charges in accordance with Article 18 of Regulation (EU) 2019/943, ensuring that they contribute in an adequate and balanced way to the overall cost sharing of the system.

2. Member States may provide in the enabling regulatory framework that citizen energy communities: (a) are open to cross-border participation; (b) are entitled to own, establish, purchase or lease distribution networks and to autonomously manage them subject to conditions set out in paragraph 4 of this Article; (c) are subject to the exemptions provided for in Article 38(2).

3. Member States shall ensure that citizen energy communities: (a) are able to access all electricity markets, either directly or through aggregation, in a non-discriminatory manner; (b) are treated in a non-discriminatory and proportionate manner with regard to their activities, rights and obligations as final customers, producers, suppliers, distribution system operators or market participants engaged in aggregation; (c) are financially responsible for the imbalances they cause in the electricity system; to that extent they shall be balance responsible parties or shall delegate their balancing responsibility in accordance with Article 5 of Regulation (EU) 2019/943; (d) with regard to consumption of self-generated electricity, citizen energy communities are treated like active customers in accordance with point (e) of Article 15(2); (e) are entitled to arrange within the citizen energy community the sharing of electricity that is produced by the production units owned by the community, subject to other requirements laid down in this Article and subject to the community members retaining their rights and obligations as final customers.

   For the purposes of point (e) of the first subparagraph, where electricity is shared, this shall be without prejudice to applicable network charges, tariffs and levies, in accordance with a transparent cost-benefit analysis of distributed energy resources developed by the competent national authority.

4. Member States may decide to grant citizen energy communities the right to manage distribution networks in their area of operation and establish the relevant procedures, without prejudice to Chapter IV or to other rules and regulations applying to distribution system operators. If such a right is granted, Member States shall ensure that citizen energy communities: (a) are entitled to conclude an agreement on the operation of their network with the relevant distribution system operator or transmission system operator to which their network is connected; (b) are subject to appropriate network charges at the connection points between their network and the distribution network outside the citizen energy community and that such network charges account separately for the electricity fed into the distribution network and the electricity consumed from the distribution network outside the citizen energy community in accordance with Article 59(7); (c) do not discriminate or harm customers who remain connected to the distribution system.

Current Swedish law encompasses all demands put forward related to active consumers but, as Article 16 is a new regulation, none of those related to citizen energy communities. The Member States was given two years to incorporate the new directives into national laws. The Swedish Energy Markets Inspectorate was therefore commissioned to formulate a proposal for such national legislation. In 2020 the proposal was sent for referral to relevant stakeholders such as authorities and municipalities, grid owners and housing associations. The suggested Swedish legislation does not allow citizen energy communities to own or operate electricity grids. However, that is not of importance from an ANM perspective, and the coming legislation may very well offer great support to DSOs and active consumers that wish to engage in this type of ANM solutions.

While citizen energy communities are not yet implemented in Swedish law, they are in the Hungarian Electricity Act. Similarly to when it comes to aggregators, there are nothing in the regulation that prevents them from working with flexibility services. There are some restrictions such as they are not allowed to engage in cross-border cooperation etc., but nothing that prevents being active offering ANM services to Hungarian DSOs.

4.4 Network tariffs

Network users pay network tariffs to the DSO. The fee normally consists of two parts; one fixed tariff that is set based on the connection size and one variable part that depends on the amount of electricity consumed. Household consumers normally pay a fixed rate regardless of when the electricity is consumed and network constraints are thus not factored in the distribution tariff. However, article 18 in 2019/943 opens for more variable network tariffs: *where appropriate, time-differentiated network tariffs may be introduced to reflect the use of the network, in a transparent, cost efficient and foreseeable way for the final customer*. Time-differentiated network tariffs enable DSOs to send price signals to customers based on system users' consumption or production profiles. For example in the Öland case where the distribution network at times is unable to transfer all wind produced electricity, the DSO can set a lower than normal tariff when wind prognosis is showing strong winds and higher than normal when wind prognosis is showing light winds. The mentioning of time-differentiated network tariffs is new in 2019/943.

While this is not mentioned in either Swedish or Hungarian law, nothing is seemingly hindering DSOs to apply a variable network tariff, as long as the tariff is non-discriminatory within a consumer group. [51] The Swedish Energy Markets Inspectorate is currently running a pilot project where DSOs are given more freedom to trial new approaches for collecting consumer tariffs that will increase the efficient utilisation of the grid (see [52] for more information). At the time of writing there are no published results from the pilot project and it is not clear how many DSOs have trialled new tariffs. In 2021 the Swedish DSO Göteborg Energi Elnät introduced a new model for network tariffs for houseowners. The new model consists of a fixed cost and two variable costs that both depend on the houseowners power outlet. The house owner pays for how much electricity the household uses (electricity transmission fee), and for how much electricity the household uses at one and the same time (power fee). The household's highest power peak during the month determines the household's power fee. [53]

4.5 Entitlement to a dynamic electricity price contract

Dynamic pricing is an enabler for flexibility as it allows consumers to adjust their consumption by reacting to a price signal, but it is not strictly necessary for ANM solutions. Grid owners are not allowed to participate on the electricity market and whether dynamic pricing is available or not to consumers when purchasing electricity from electricity suppliers or not is not critical. However, it may be easier to implement ANM solutions that involve action from consumers if they are used to dynamic pricing and have access to a smart meter.

Article 11 in 2019/944 states that all Member States must ensure that electricity suppliers are able to offer dynamic pricing to consumers with smart meters, and that those consumers can request a dynamic electricity price contract from at least one supplier. All suppliers with more than 200 000 customers must be able to offer a dynamic electricity price.

Member States must ensure that the suppliers provide consumers with information about opportunities and risk, costs, and the need of a smart meter. National regulatory authorities are responsible to assess risks and prevent abusive behaviours related to dynamic pricing.

Swedish electricity suppliers are not hindered in any way to apply dynamic pricing and most suppliers offer it if they are able, i.e., if the consumer has a smart meter installed. Hungarian electricity providers must, according to section 45 of the Electricity Act, provide one or more contracts based on dynamic pricing to final consumers.

5 OPERATIONAL REGULATION

5.1 Order of prioritisation

The ANM4L project does not discriminate between different technologies and ANM solutions, and the task of prioritisation between different alternatives is therefore relevant. The DSO may have multiple ANM solutions available for solving a grid problem and while technical and financial aspects are evident the regulatory aspects must also be considered when deciding which ANM solution should manage the problem.

Article 12 and 13 in 2019/943 states that the system operators must prioritise to keep production of renewable energy sources active when facing a situation that forces them to dispatch production. This means that non-renewable alternatives and alternatives that does not hinder production of renewable electricity should be dispatched first.

The absolute majority of all production facilities in Sweden are renewable or nuclear hence the prioritisation problem is less of an issue. However, although not demanded by regulations, there may be reason to prioritise adjusting loads and utilising equipment in the grid. As countries become more interconnected the production mix of each individual country becomes less important and the combined production mix becomes increasingly important, especially for exporting countries. If a producer of renewable electricity in Sweden curtails their production, it may lead to a producer of non-renewable electricity compensate for the curtailed production instead of renewable electricity being imported. Hungary has an energy mix involving more fossil energy sources, see Figure 33, and should therefore aim to dispatch energy from those sources first or utilise other ANM solutions if possible.

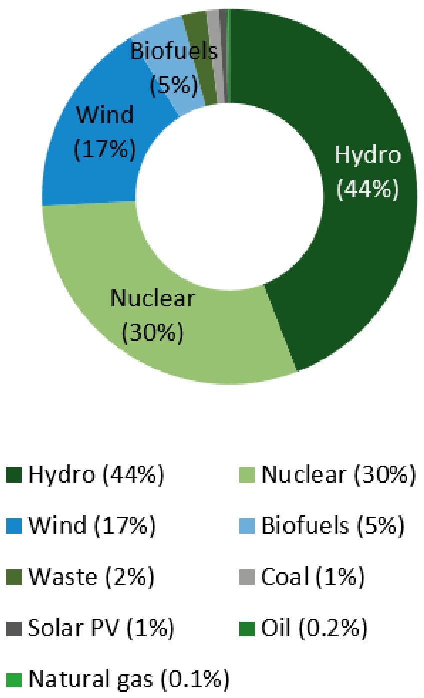

Figure 32 Electricity generation by source, Sweden 2020 [54]

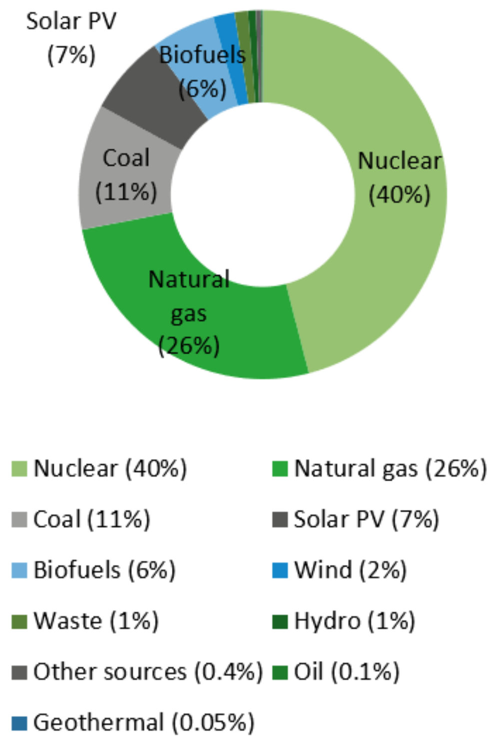

Figure 33 Electricity generation by source, Hungary 2020 [54]

5.2 BRP

There are two potential challenges related to balance responsibility and ANM solutions:

- First, when curtailing electricity production, it may be that the production plans reported by the producer no longer match the actual production upon evaluation. This can lead to the relevant BRP facing financial charges.
- Second, as briefly mentioned previously, active consumers and other flexibility providers are responsible for any imbalances they may cause.

There are no alleviating measures for small flexibility providers such as private households or small firms. While it is unlikely that this would lead to any actual issues for these parties, as it will likely be solved through contracts and would amount to small numbers, it may however hinder participation due to uncertainty.

The Hungarian Electricity Act (Section 66/D) states that “the aggregator shall be subject to financial responsibility for any imbalance caused in an alien balance group reduced or increased by the imbalance adjustment” meaning that the consumer will not be financially hurt by any imbalance fees as long as they are connected to an aggregator.

Furthermore, Regulation 2019/943 states that pricing methods for any "products for balancing electricity should create positive incentives for market participants in keeping their own balance or helping to restore the system balance in their imbalance price area, thereby reducing system imbalances and costs to society" which indicates that the DSO when entering a contract with a smaller flexibility provider should ensure that they will be protected against any imbalance fees if they arise as a consequence of the DSO activating an ANM solution.

6 STATUS OF FLEXIBILITY IN SWEDEN

Every year since 2015[7], the Swedish Energy Markets Inspectorate examines the current state of flexibility services. [49] As part of these examinations, market participants are invited to share their views on desirable requirements, barriers and overall conditions for flexibility, either as ancillary services or as electricity for sale. The discussions mainly focus on services involving third parties and not internal ANM solutions.

The barriers brought up in these investigations are interesting from a regulatory perspective if they persist over time, and if there are reason to believe that the market is unable to overcome them.

6.1 DSO requirements for third parties

In the investigation from 2020[8], as well as in previous investigations, most DSOs state that they have not been approached by any new or existing market participants regarding flexibility and if it were to happen, they do not have any *formal* technical requirements on customers or aggregators providing services for changing electricity consumption, however there are examples of technical demands that they would like to see fulfilled in order to enter into an agreement: [49]

- Any installations of equipment should be performed by a licensed electrician and the equipment must not disturb the DSOs communication with the smart meter or negatively affect the quality of supply.
- The DSOs want to make sure that the flexibility services offered by consumers and aggregators are reliable, efficient, and available as expected. In the 2020 investigation the DSOs formulated the following criteria for fulfilling a reliable, efficient, and available service.
- Product requirements such as activation within a certain time frame, reliability, availability as promised and ability to validate the called service.
- Requirements for interoperability such as the use of a common platform and API for smooth communication programs and platforms.
- Requirements for data exchange, such as forecasts for access to flexibility.

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7 Except in 2016 due to the publication of reference [71].

8 The latest available as of finalising this report in September 2021.

- Technical requirements regarding, for example, control systems and technical equipment.
- Requirements for information to electricity network companies.
- Requirements for balance responsibility.

Some general non-technical demands are also put forward by the DSOs, most of administrative nature. If an aggregator wishes to access any measuring data of a consumer, prosumer, or producer the aggregator must bring forward a power of attorney and in order to receive real time data an agreement must be signed with the DSO. In addition, the general terms and conditions for connection of electrical installations to electricity networks and transmission of electricity to such installations developed by the industry association Energiföretagen Sverige AB and the Swedish Consumer Agency must be complied with. Most DSOs would also find it convenient if services from third parties is based on third party's own applications and software. [49]

In summary, the demands put forward by the DSOs are to a large extent related to being able to trust the services provided and thereby ensure the security of supply of electricity.

6.2 Observed barriers

DSOs experience challenges with having flexibility solutions as part of their network planning. Uncertainties regarding reliability, such as correct, standardised measurement values, and the flexibility resources' availability over time are addressed. [49]

In addition, several problems are expressed regarding economic viability. The DSOs fear that many flexibility solutions are cost-driving and difficult to make profitable. At the same time, they find it difficult to motivate customers, both private households and small businesses, to participate in flexibility solutions due to a lack of financial incentives. This means, for example, that the opportunities for savings or extra income are considered to be low, but also a lack of knowledge about flexibility and its benefits is deemed problematic. Positive environmental values are not considered significant enough either. [49]

Players who can or want to provide flexibility services to DSOs also experience problems with profitability. It is difficult to offer products in a yet undeveloped market with a lack of willingness to pay and a lack of standardized products. [49]

Furthermore, obstacles linked to the balancing market are also identified. There is a lack of balance market products adapted to decentralised small units. For example, there is a requirement for pre-qualification per unit and there are no balancing market products suitable for aggregation. [49] However, the issue of balancing markets is related to flexibility at the system level and not the local level which is the focus of this report.

7 DISCUSSION

The new Directive on common rules for the internal market for electricity (EU) 2019/944 and the Regulation on the internal market for electricity (EU) 2019/943 offer support for flexibility, including different ANM solutions such as those utilising equipment in the grid and flexible consumers. However, the new regulations and directives are not yet implemented in Swedish law and whilst Hungary has come further regarding the legal framework, the market for alternative gird operation has yet to take off. This discussion focuses on financial barriers hindering development identified in the regulation and in the annual investigation by the Swedish regulator, starting with the incentive regulation.

DSOs are inherently risk averse and not willing to invest in a solution that may not work as planned, both in terms of technical and financial aspects. Risk aversion is embedded in the fundamental operation of DSOs given the importance to society of secure and efficient electricity supply. This is reflected in the regulatory frameworks that determine the DSO role, responsibilities, and its revenue. For DSOs to better utilise available flexibility services, changes further down the regulatory chain of command are necessary, particularly in the method of economic incentive regulation. One such change could involve a framework which removes the separate treatment of OPEX and CAPEX and instead introduces a TOTEX approach. It is also possible for regulators to introduce new and innovative incentives to steer DSOs towards certain behaviours. However, the regulatory framework must keep its main focus on safety and security and remain predictable to avoid mixed signals and inefficiency through stranded or avoided investments.

To limit the financial uncertainty DSOs must perform analyses and develop methodologies that allows them to assess what is the most efficient option. This can be done by a cost benefit analysis. In the ANM4L project a simplified cost benefit analysis to be used as a first assessment is being developed. Its purpose is to swiftly compare two or more scenarios involving different types of solutions to a problem, for example ANM solutions or network expansion, and use the results to identify which scenarios to focus on in an extended analysis. The financial risk will most likely never be eliminated but only limited, meaning that the DSO must be willing to take on some risk. The technical uncertainty for the DSO is also challenging but is already being managed through various pilot and demonstration projects such as ANM4L.

Further regulatory changes could boost the utilisation of flexibility in the distribution networks, however, there are additional factors hindering development and the role of regulation is not to push actors into participating on a market that they otherwise would have avoided. The fact that there are additional factors hindering development is evident from the annual investigation of the Swedish Energy Markets Inspectorate, see chapter 6.2.

When focusing on ANM solutions that involve active customers, aggregators, and other similar actors, it seems that these actors are also facing financial barriers. Due to the inelastic nature of price elasticity of electricity pure monetary incentives to engage consumers are likely not enough. Based on the annual investigation of the Swedish Energy Markets Inspectorate there is likely a lack of knowledge on the customer side which may mean that if the general public was better informed they would potentially show greater interest.

To enable trade, all actors in the value chain must benefit. The DSO must find the ANM solution to be the most efficient solution to their problem[9], the aggregator (if any) must profit[10], and the customer must find that the benefit exceeds any inconvenience and cost, monetary but also time spent.

9 Here, the incentives regulation is relevant.

10 Unless the aggregator is a citizen energy community, then they must only cover their costs.

CHAPTER 5: VALUATIONS OF ANM IN SHORT- & LONG-TERM PLANNING

(ANM4L DELIVERABLE D3.2&4.4)

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1 CHARACTERISATION AND VALUATION OF ANM

Through network planning, distribution system operators (DSOs) strive to ensure safe and reliable operation in a continuously changing system environment. Planning over multiple time horizons enables the DSO to select adequate operational strategies (short-term planning), as well as obtain support in investment decision making (long-term planning). Short-term planning is typically performed on an inter-day or an intra-day basis and requires detailed modelling to achieve high precision assessments of operational conditions. In this case, access to high resolution data, including weather forecasts, allows for estimation of near-future generation and demand. In contrast, long-term planning is related to future infrastructure investments and is thus relevant on a time scale of months to several years. The longer time perspective means predictions are more reliant on data of lower granularity. At the same time, assessment is widened with the inclusion of additional economic and legal parameters. In this context, it is possible to holistically compare different investment strategies.

The purpose of the active network management (ANM) algorithms developed in the ANM4L project is to provide an alternative to traditional grid reinforcement strategies in distribution networks with a rapidly increasing share of variable renewable energy resources. A long-term planning method is needed to compare the ANM solution with other network investment strategies in an ordered and transparent manner. This chapter outlines a common framework for techno-economical assessment of active network management and grid reinforcement strategies.

1.1 Estimation of flexibility in long term planning

The basic principle of the developed ANM algorithms (described in Chapter 2) is to safely allow network operation up to the operational limits. The limiting quantities considered are the maximum allowed bus voltages and the loading limits of lines and transformers. To avoid network constraint violations, ANM controllers adjust active (P) and reactive (Q) power set points of flexibility resources. Renewable energy resources, such as wind power plants and PV systems, as well as loads are considered as potential resources. A characterisation of various flexibility resources is presented in deliverable 4.2 (D4.2). To evaluate the costs associated with the use of flexibility, the amount of energy (e.g., in MWh and Mvarh[11]) utilised in an ANM scheme should first be estimated. This is done by simulating the effects of selected planning scenarios on a network model, from which the required flexibility need can be extracted.

1.1.1 Power system modelling for long-term planning

The ANM algorithms are based on feedback control which facilitates real-time adjustment of power injections. This approach allows for limited use of network

[11] Duration of reactive power provision

data, and supports model-free implementation in operation, which makes the solution highly scalable and simplifies deployment. However, to assess the performance of the algorithms at the planning stage, simulating operation in a network model is necessary. In a short-term planning context, the discrete-time ANM algorithms can be evaluated through iterated load flow simulations, which, when combined with forecasted hourly or daily load and generation profiles, yield a comprehensive view of their operational performance. In theory, the procedure can also be applied to evaluate flexibility in the long-term planning stage, using an updated model with the planned changes to the network. In practice, two key features of this simulation approach, makes it less attractive for use in long-term planning.

- The quality of demand and generation forecasts quickly deteriorates as the prediction time range is increased.
- The ANM controllers operate on a time scale in the range of seconds. Simulating real-time operation iteratively for longer time periods to obtain seasonal or yearly flexibility need becomes computationally expensive.

A straight-forward method to manage the first issue is to instead use historical measurement data for flexibility estimation. These data can be scaled to match expected peak or average value of generation and/or demand in a future scenario.

The second issue is addressed in three steps. First, the full network model is replaced with an approximate one, which eliminates the need to conduct full load flow computations. Second, time series data with lower resolution is accepted, which reduces the number of iterations required in the simulations. Third, the time constant of the ANM controller dynamics is considered negligible in relation to the time series data resolution. Assuming stable system behaviour, no explicit modelling of the ANM controllers is needed, and the flexibility need is instead extracted directly using known network limits. The modelling procedure is described in detail in the following sections.

1.1.2 Network model approximation

Starting from a full network model, a single power flow computation for a given operational scenario is used as a basis for calculating the power transmission distribution factors (PTDF) and the voltage transmission distribution factors (VTDF) of the network. The PTDF yields the sensitivity of the power flow through a network branch to a variation in power injection at a specific node. Similarly, the VTDF gives the voltage sensitivity to power variations. The PTDF for a network branch starting at a node *j* to a power variation at node *i* can be expressed in terms of apparent power as

$$PTDF_{i,j} = \frac{S_{0,j} - S_j}{S_{0,i} - S_i},$$

where S_0 is the power in the base power flow computation. The corresponding voltage sensitivity equation is

$$VTDF_{i,j} = \frac{V_{0,j} - V_j}{S_{0,i} - S_i}.$$

The network sensitivities are combined with load and generation profiles to generate an estimation of network flows and voltages. The linear approximate model used can, for all nodes *i* and *j* in the network, be expressed as

$$S_j(t) = S_{0,j} + PDTF_{i,j} \cdot \sum profiles_i(t),$$

$$V_j(t) = V_{0,j} + VDTF_{i,j} \cdot \sum profiles_i(t).$$

Load and generation connected to the same node are aggregated in the model so that the net power injection (represented by $\sum profiles$) at each time instance is used. Assuming all loads and generators have a constant power factor, the active and reactive parts of the total flow are approximated for each time instance.

In a long-term planning scenario, time series data for expected future generation and demand also must be estimated. Here, it is assumed that scaling of available historical profiles with respect to the expected peak demand and planned installed generation capacity respectively yield a sufficient description of future operating conditions. Note that that no ANM solution or network reinforcement is assumed to be implemented at this point.

When the estimated flows and voltages have been obtained, the results are compared to the operational limits of existing network components. Conventional long-term planning for grid reinforcement typically involves simulation of worst-case scenarios with subsequent modelling of reinforced models to verify that the intended actions give the desired operational results. The peak power flows and largest changes in voltage levels from the time series computations represent such worst-case scenarios and can therefore be used as a basis for modelling potential network reinforcements.

1.1.3 Modelling flexibility need

The estimation of the flexibility need with the ANM solution in the long-term planning phase is solely based on the difference between the stated network limits and the estimated power flows at each time instance. In terms of overloading this approach is straight-forward: the estimated flow through a line or transformer is evaluated against its rated power (statically or dynamically). The flexibility need for the monitored component is then the total amount of excessive power during the simulated period. This need can then be further divided into active and reactive power flexibility demand. An example using active power is shown in Figure 1, which depicts a line loading duration curve in a future scenario where a significant increase of distributed generation capacity is expected. Using estimated load and generation profiles with hourly resolution, the hourly average active power flow through the line is computed for 120 hours and sorted by decreasing magnitude. The estimated flexibility need is then the total energy, $\frac{MWh}{h} \times \#h$, i.e., the hourly average times the number of hours above the rated line capacity (dotted line).

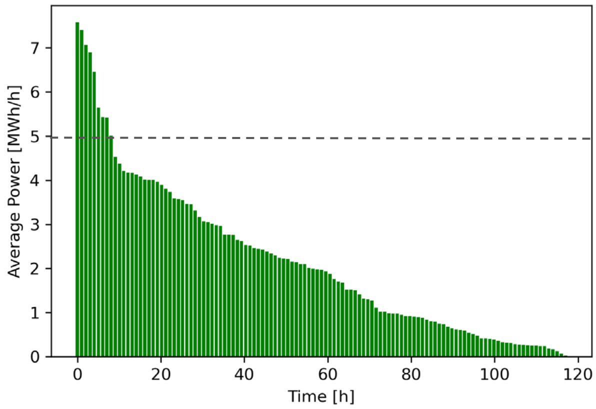

Figure 34. Flexibility need estimation example. Line loading duration curve for scenario with future expansion of distributed generation. The flexibility need is the total energy above the line loading limit (black dotted line).

To estimate the flexibility need resulting from voltage constraints, simulated voltages are converted to a corresponding power injection level. This is done separately for active and reactive power injections according to the following algorithm:

$$if\ \Delta V_j = V_{est,j} - V_{max,j}\ > 0:$$

$$\begin{cases} \Delta P_i = \dfrac{\Delta V_j}{VTDF_{i,j}^P} \\ \Delta Q_i = \dfrac{\Delta V_j}{VTDF_{i,j}^Q} \end{cases}$$

where the VTDF superscripts *P* and *Q* indicated the voltage sensitivity at node *j* to a change of active or reactive power at node *i*. The resulting powers ΔP_i and ΔQ_i are the maximum active or reactive power needed at node *i* to mitigate the overvoltage at node *j*.

Controlling the power flows and voltages across the network means that there will be multiple parallel flexibility needs with different magnitudes and at different locations. Establishing the total flexibility need is closely related to the choice of ANM solution, which is presented in the section 1.1.4.

1.1.4 Modelling ANM algorithms

The functionality of the ANM control algorithms is described in detail in Chapter 2. In the developed long-term planning process, the controller outputs in case of ANM operation are modelled implicitly. This assumes that the ANM controller dynamics is fast, and that system operation is always stable.

The ANM algorithms also manage the distribution of flexibility set points to participating resources. Depending on which network issues are to be addressed, which type of resources are available, and what financial arrangements are in place, the distribution of set point may vary greatly. A simplified modelling approach is proposed in this report. It establishes a predetermined order of activation of resource categories, subject to activation constraints set by the planner. Without any set activation constraints, and provided that both types of flexibility (both active and reactive power) are needed to mitigate an issue, flexibility is distributed in the following order:

- *Reactive power from* renewable energy resources until issue is mitigated, local resource limits reached, or negative interference with other control objectives occurs. (The last condition is relevant when simultaneously preventing voltage and congestion constraint violations.)
- Active power from flexible loads until issue is mitigated, local resource limits reached.
- Active power from renewable energy resources until issue is mitigated, local resource limits reached.

The order stems from the assumption that the cost of reactive power usage is significantly lower than changing active power set points regardless of resource type. Furthermore, an increase of load active power implies a time shift in energy consumption, which is seen a preferable to the unutilised renewable energy associated with curtailment of generators. Lastly, as the algorithms are designed to manage network issues created by large renewable energy production, sufficient curtailment of generators guarantees operation within voltage and congestion constraints.

The planner can then alter the estimated flexibility need by choosing to activate any combination of the above flexibility categories before executing a simulation of a long-term planning scenario. The distribution of flexibility to individual resources is done during the simulation, and that process is described in section 1.1.5.

1.1.5 Computing flexibility usage

To estimate the volume and distribution of flexibility usage for the available resources at each time-step of the simulation, the maximum control error signal in case of a network constraint violation is first used to determine the set of flexibility resources that can be activated, and the amount of flexibility needed locally. For congestion management, the approach is again relatively straight-forward. Since a centralised ANM algorithm is required, the largest power/current constraint violation at each radial network feeder determines the total local flexibility demand for active power and, if desired, reactive power. Additional bottlenecks on the same feeder set the minimum flexibility requirements for their respective sections. Resulting set points are then proportionally distributed within each section. The predetermined order of activation is also considered in this step. Note that this practice replaces the flexibility dispatch method of the original ANM algorithm, and, more importantly, assumes that the variation in PTDFs at a feeder is small, i.e., the impact of location on flexibility need and provision is negligible. To improve accuracy, local sensitivity factors can be used to determine all different flexibility needs relative to a reference point in the network (e.g., the location of the largest control error). An example of the flexibility estimation process for congestion management is given below.

Example 1: determining flexibility need and identify resources for congestion management.

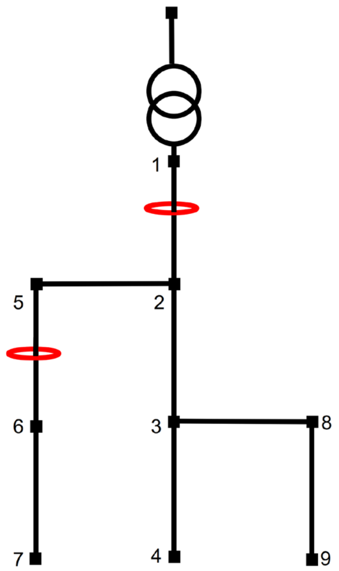

Figure 35. Radial distribution network feeder.

In the radial distribution network feeder (left), the lines L1-2 and L5-6 (marked in red) are monitored for congestion. Assuming all lines in the feeder have the same capacity limit $S_{\max}$ and that there exists a power flow such that $S_{L1-2} > S_{L5-6}$, the total flexibility for the feeder is determined by $S_{L1-2} - S_{max}$. Flexibility is distributed among available resources at nodes 2-9. The flexibility need set by $S_{L5-6} - S_{max}$ determines the minimum flexibility to be allocated to resources at nodes 6 and 7, with the remaining flexibility to be distributed proportionally between nodes 1-5 and 8-9.

The ANM algorithm for voltage management can be implemented locally or in a centralised control system. However, as the voltage sensitivity with respect to the power flows has a large locational variation due to the influence of line resistances and reactances, only flexibility resources situated close to the location of a voltage constraint violation should be activated. In this report, a 'one-size-fits-all' approach is taken to estimate flexibility need for voltage management regardless of the structure of the ANM algorithm. It prescribes that the resource closest to a detected constraint violation activates the flexibility needed to mitigate overvoltage. If a local flexibility limit is reached, the time-step is re-evaluated using the updated power injection from the resource. The remaining flexibility need to the closest neighbouring resource(s) in an iterative manner following the predetermined order of activation of resources. In case of multiple constraint violations, the largest disturbance will be managed first, as in the following example.

Example 2: determining flexibility need and identify resources for voltage management.

Consider the network in Figure 35 and assume that coinciding large generation and low demand at the feeder at one time-instance creates overvoltage issues. In the radial feeder, the issues are expected to occur at the end of network branches. Let $V_7 > V_4 > V_{max}$ where V_i is the voltage at node i and V_{max} is the upper voltage limit. Flexibility usage is then computed as follows. The reactive power ΔQ_7 corresponding to achieving $V_7 = V_{max}$ (see section 1.1.3) is requested from flexibility resources at node 7. If a local limit is reached, a re-evaluation of the time-step is done with the updated reactive power injection. ΔQ_6 corresponding to $V_7 = V_{max}$ is then calculated and flexibility from resources at node 6 is requested. If the reactive power resources at the network branch have been exhausted, ΔP_7 corresponding to $V_7 = V_{max}$ is computed in the subsequent re-evaluation and is then assigned to flexible loads at node 7. Only after the total flexibility needed to reach $V_7 = V_{max}$ is determined, the (updated) overvoltage issue at node 4 is addressed. When $V_i \leq V_{max}$ for all nodes, the total flexibility required in the simulated time-step is summarised.

When studying a combination of voltage and congestion management algorithms in long-term planning, the flexibility estimations are first calculated separately, with some additional constraints. These constraints are linked to the demand for reactive power. An increase in reactive power flows through the network due to voltage control actions might cause congestion if not treated with care. At the same time, adjusting reactive power injections of flexible resources to reduce the flow of reactive power through congested lines can cause unacceptable voltage increases. The estimated total flexibility use is then determined by the greatest demand at each node (comparing the voltage and congestion flexibility demands).

Modelling of control of the reactive power flow at the TSO/DSO interface follows the congestion management structure. However, only reactive power resources are considered, and both voltage and congestion constraints throughout network feeders apply as well. In practice, it gives this control method lower priority than the equally prioritised voltage and congestion management algorithms.

Finally, the total need for flexibility, as well as the aggregated distribution of flexibility among different resources can be computed by summarising the results from all simulation time-steps. The results can then be used to estimate the costs related to investments in ANM solutions.

1.1.6 Network simulation input

To run the flexibility estimation program, network sensitivity factors, and timeseries data must be made available. Several technical parameters must also be defined, these are:

- Start- and end point of time-series simulation.

- Resolution of time-series data (required for flexibility estimation).
- Installed capacity of generators.
- Maximum demand of individual load buses.
- Nominal power factors of generators and loads.
- Network constraints (voltage, power).
- Specification of available flexible resources.
- Power factor limit (reactive power flexibility).
- Load increase limit (active power flexibility).
- Curtailment limit (active power flexibility).
- Which flexibility types to consider (see 'order of activation' in section 1.1.4).

1.1.7 Network reinforcements

Section 1.1 outlines how flexibility usage can be estimated in a long-term planning scenario with the deployment of an ANM solution. The network reinforcements required to achieve equal operational safety and reliability are in this report assumed to be determined using conventional methods, i.e. using a worst-case operational scenario and run simulations in a network model, where network components are manually reinforced until all operational criteria are met.

1.1.8 Energy losses

The transfer of power throughout the network leads to losses in power lines and transformers. Loading of components generate heat dissipation proportional to the square of the current and the resistance. In distribution networks, both overhead lines and cables are used, and the resistance is affected by factors such as choice of conductor and ambient temperature. In transformers additional losses stem from hysteresis and eddy currents. Since the purpose of the long-term planning method is to compare different investment strategies, a practical approach is taken with respect to estimation of losses in this report. Distribution lines are assumed to be short and have constant resistance given by the manufacturer's data sheet. Data sheet values for transformer no-load and loading losses are also used. Total losses are then estimated from time-series simulation of ANM and non-ANM scenarios respectively. Note that this requires a transfer of the network reinforcement solution to the simulation framework presented in the previous sections.

1.2 Cost estimation & Cost Benefit Analysis (CBA) for long term planning

When a DSO is faced with an issue in its grid, they may have multiple alternative solutions to that issue. Some solutions may be swiftly implemented and permanent, solving the issue for many years to come, some may be swiftly implemented but temporary, solving the issue for the nearest future but will need complementing efforts or replacing investments in the coming years, and some may take some time to implement but will solve the issue for many years to come. An example of the first and second may be an ANM solution, the second shortly complemented by a grid reinforcement or other investment and the third may be a grid reinforcement or other change to the grid infrastructure.

The challenge for the DSO is to assess which solution or combination of solutions is most profitable with regards to cost in terms of time, new connections, economic regulation etcetera. A CBA may be a helpful tool to the DSO as it takes time into consideration, focusing on the value of an investment from a long-term planning perspective, and is able to compare the net present value of multiple alternative solutions.

A drawback of CBAs is that they are time consuming to perform. To alleviate this, the ANM4L project has developed a model that allows for quick analysis. Although it is not as precise as a full-scale CBA it allows for an initial estimation comparing different alternative investments and assessing which alternative or alternatives to investigate further.

As described in Chapter 1, the CBA may also be useful for other purpose such as evaluating a regulatory model, to analyse if it incentivises efficient investments, or to estimate a maximum long-run average price that the DSO is willing to pay for flexibility services.

In this section the CBA developed for the ANM4L project is described.

1.2.1 Required input

The input required for the CBA is limited to simplify the analysis as much as possible for the DSO. The required input is the following:

- Scenario name

  As the model allows for several solutions to be evaluated simultaneously it is important to define a scenario name for each solution. The scenario name is defined by the user.

- Type of project

  A typical ANM solution has a shorter expected life span than a grid reinforcement and the model therefore treat ANM solutions and grid reinforcements differently (this difference is described below). There are three pre-defined type of projects: ANM, Grid and Combo. The ANM is a pure AMM solution such as utilising DLR or DSM. Grid is a pure grid extension solution such as installing higher-capacity transformers or upgrading distribution lines. Combo is a combination of the two, where the name stems from the need to combine network reinforcement with the ANM solution. The type of project is selected from a dropdown list by the user.

- Total investment cost during planning phase

  The user needs to estimate the expected total investment cost during the planning phase. This includes labour costs, any costs related to applications, etcetera. If project type is ANM, only the ANM cell should be filled out and similarly for Grid, if the project type is Combo both cells should be filled out, one for each investment.

- Total investment cost during construction/implementation phase

  The user needs to estimate the expected total investment cost during the construction or implementation phase. This includes material and construction cost, labour costs, etcetera. If project type is ANM, only the ANM cell should be filled out and similarly for Grid, if the project type is Combo both cells should be filled out, one for each investment.

- Estimated yearly cost of flexibility

  For project type ANM and if the solution involves purchasing flexibility the estimated yearly cost for the needed flexibility should be added. This cost is estimated and added by the user. As a guide, the energy price of Power Purchase Agreement (PPA) can be used as the cost for flexibility since most wind power plants have PPA to secure the investment. This cost can also be applied to the flexibility provided by others in the grid.

- Estimated yearly cost of energy loss

  The user needs to estimate the yearly cost of energy losses for all project types. Only the parts of the grid that are affected need to be considered. As a guide the energy losses are expected to be more server for solutions that maximise the utilisation of the grid as an ANM solution is likely to do compared to a grid extension. The cost can be set to zero.

- Connection fee

  If the DSO expects to receive any connection fee payments from new connections that are made possible thanks to the investment, this revenue should be added here. If project type is ANM, only the ANM cell should be filled out and similarly for Grid, if the project type is Combo both cells should be filled out, one for each investment with the estimated amount related to each respective investment. The revenues are estimated by the user.

- First year of planning

  The user must indicate the expected first year of planning. If project type is Combo, it is assumed that the planning for both investments start at the same time, however the length of the planning phase may differ as explained in the following bullet.

- Total number of years spent in planning phase

  The user must indicate the expected number of years that will be spent in the planning phase before construction or implementation is initiated. If project type is ANM, only the ANM cell should be filled out and similarly for Grid, if the project type is Combo both cells should be filled out, one for each investment with the estimated amount spent in the planning phase.

- Total number of years spent in construction or implementation phase

  The user must indicate the expected number of years that will be spent on construction or implementation. If project type is ANM, only the ANM cell should be filled out and similarly for Grid, if the project type is Combo both cells should be filled out, one for each investment with the estimated number of years spent on construction and implementation.

- Discount rate

  The discount rate should reflect the opportunity cost of capital, taking the riskiness of the investment into account, and mirrors present value of future cash flows in a discounted cash flow analysis which this CBA is. The user is asked to select a discount rate and add it as an input. As a guide, it is common to use the weighted average cost of capital (WACC).

Only costs and revenues that are directly related to the investment in question should be included. If there are costs that are needed for all alternatives these can be left out. Costs and revenues can be added in any currency if it is the same for all.

1.2.2 Assumptions

As mentioned above, a full-scale CBA is time-consuming, and the model has therefore been adapted to require as little input as possible. To enable this, several assumptions are necessary. These assumptions also make it possible to compare different alternatives. If needed these assumptions are easy to change.

- Life span of a grid expansion (new line etc.) is set to 50 years
- Life span of an ANM solutions is set to 10 years
- Operation and management cost per year for grid expansion is set to 5 % of CAPEX.
- Operation and management cost per year for ANM is set to 10 % of CAPEX, a slightly higher share of CAPEX compared to grid expansion assuming that the ANM solution will be more demanding in operation. This can be changed in the script.

If the first year of planning differs between the alternatives the years in between will be inactive years for the alternatives that starts after the first starts. This is due to that the CBA will relate the cost to the same year (the current year) to make them comparable.

The alternatives that are being compared also need to have the same total length of time. The length of an alternative is the sum of inactive years, planning phase, construction or implementation phase, and the life span of the investment. The alternative with the longest time will set the total length of time and all the others will be expanded through reinvestments to reach the same length.

To make the alternative have the same length of time, the shortest ones are expanded with a multiple of the length of the life span of the investment. The CBA calculates how many reinvestments that can be done during the remaining years and the cost for making this investment is also added. If the difference is not a complete life span it will be adjusted to only add the cost for that part of the investment that is needed to expand the length to the same as the alternative that has the longest time length, see Figure 36.

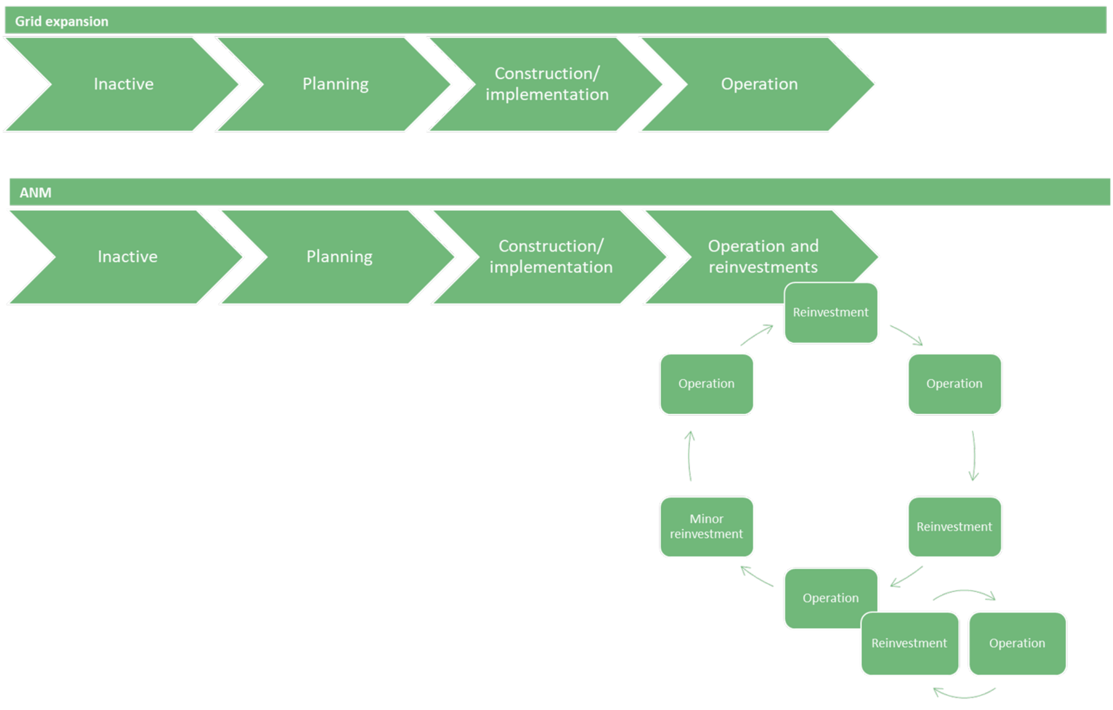

Figure 36. The different phases of a grid expansion and an ANM in the CBA model.

1.2.3 Interpretation of the NPV

The CBA results in a net present value (NPV) estimation for each scenario. The produced NPVs are comparable due to the reinvestment assumption described above. If one would like to estimate the NPV without reinvestments one can remove the scenarios with longer life span.

If the NPV is positive, it means that the expected revenues are greater than the expected costs and that the investment is profitable. If the NPV is negative the expected costs are greater than the expected revenues and the investment is not profitable.

When comparing multiple alternatives one can choose to compare them to a business-as-usual (BAU) case or, if BAU is not an option, each other. If comparing with BAU it is important to include all costs and revenues that are related to the non-BAU alternatives, however when comparing two new alternatives one can exclude identical costs and revenues as these will cancel out in the comparison. When interpreting the NPV for one scenario, it is important to be aware of whether all costs and revenues are included or not.

1.2.4 Pros and cons of the CBA tool

The tool is designed to be as easy to use as possible for a wide variety of professionals. The upsides are that the tool is easy to use and it is easy to compare multiple similar scenarios, allowing for quick sensitivity analyses etc. The downsides are that the scenarios that can be tested simultaneously cannot differ from each other in terms of life span and that an investment in a scenario cannot cease. It is possible to test a scenario where for example, an ANM solution is implemented year 1, operated for 5 years and then replaced by a grid solution. However, the two investments of this Combo project type must be evaluated separately because the tool will otherwise assume that the ANM solution will continue in operation until the end.

The alternative to this simplified tool is a traditionally structured CBA, as depicted in Figure 37 below, where a table is used to insert the estimated costs and benefits for each year of a project. The upside of this structure is that a scenario can take many forms, such as the scenario described in the previous paragraph. The downsides are that it may be daunting to fill out information for multiple years, that it may be less straightforward to compare different alternatives and perform sensitivity analysis and that it is not possible to integrate with the overall planning tool.

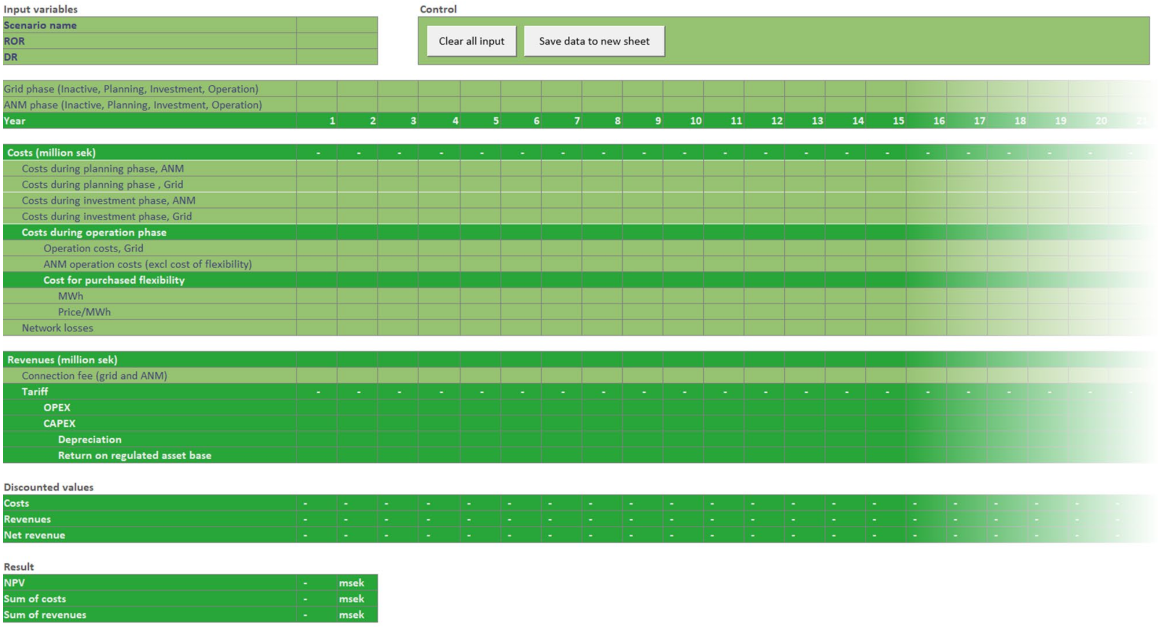

Figure 37. A traditional CBA structure.

1.3 KPIs

Key performance indicators for the ANM4L project are described in [55]. With respect to the long-term planning method, the KPIs listed below are relevant when evaluating the ANM algorithms.

- KP1 1: Loading of key transformer(s) or line(s).
- KPI 2: Increased installed capacity of (renewable) distributed generation.
- KPI 3: Increased electric energy produced by (renewable) distributed generation.
- KPI 5: Deferred network expansion costs.

2 STUDY CASE

One goal of the ANM4L project was to demonstrate the functionality of the ANM algorithms. As a this work, a realistic planning scenario was developed. It includes a large expansion of wind power in the E.ON distribution network on the island of Öland, Sweden. The long-term planning method is applied to the scenario to evaluate different investment strategies, including the use of an ANM solution.

2.1 Long-term planning: Öland study case

The future scenario is presented in the first section, followed by a techno-economical assessment of investment strategies needed to maintain safe and reliable network operation in a long-term perspective. The intention is to demonstrate how the long-term planning method can be applied in practice.

2.1.1 Expansion scenario

The Öland study case is centred on a 50 kV overhead line connected directly to the 130 kV/50 kV substation. The voltage on the secondary side of the transformer is adjusted so that the operating voltage is 1.02 pu (54 kV). At the other end, there are currently loads (4 MVA peak) and a wind power plant (rated 10 MVA) are connected via separate transformers (6 & 12 MVA respectively). This is illustrated in Figure 38. The rating of the overhead line is impacted by e.g, ambient air temperature and wind speed. During normal operation one of two static ratings, 20 MVA (summer) and 32 MVA (winter) is applied depending on the weather conditions. The voltage limit is ±6 % of the operating voltage.

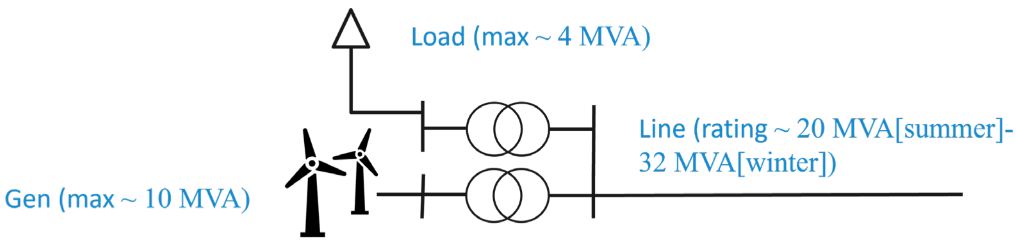

Figure 38. Öland study case. Current topology of 50 kV feeder.

The future scenario consists of the addition of a new 20 MVA wind power plant at the end of the feeder. Adding that significant amount of generation requires a new transformer to be constructed, as seen in Figure 39. Given that the rating of the new transformer is sufficient for the peak wind power generation, the loading of the overhead line, and the voltage level at the point of connection of the wind power plant are the two primary operational concerns. Network issues that arise can be alleviated by reinforcing the network feeder or implementing an ANM solution. The two options will be referred to as the *Grid* and *ANM* scenarios. The reinforcement strategy considered here, consists of replacing the current 3x99 mm^2 aluminium conductor overhead line with a new one, with a cross-section area of at least 185 mm^2, see e.g, [56].

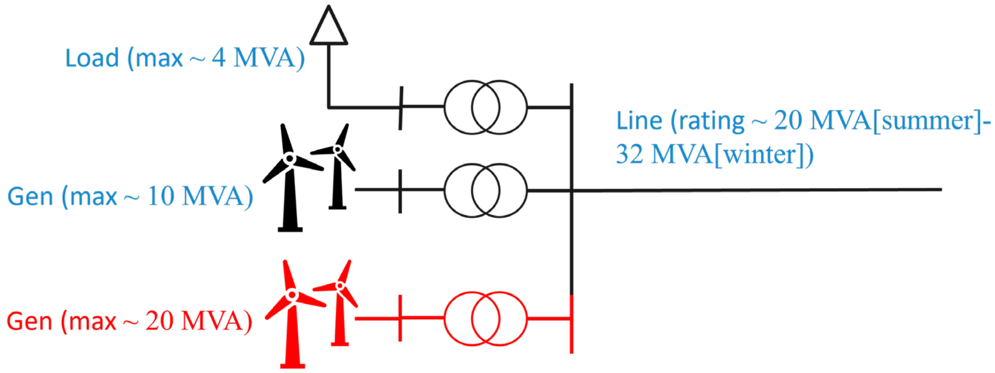

Figure 39. Öland study case. Future connection of wind power plant (in red) to feeder.

2.1.2 Simulation inputs

Sensitivity factors were obtained following a single load flow computation in a power system model of the Öland 50 kV network provided by E.ON Sweden. Publicly available times-series data for the total wind power production and demand in Sweden 2021 [57] with hourly resolution were used to model the variations in demand and generation. Yearly changes in consumption or generation levels were not modelled, i.e. the resulting flexibility usage from a single year simulation was assumed to be valid for the annual flexibility need in the CBA.

As the rating of the line under winter conditions is above the worse-case loading conditions, only the summer conditions were considered when setting the line loading limit. For simplicity, it was assumed that summer conditions apply 1 May - 31 October, and winter conditions the remaining six months of the studied year. Consequently, the simulation start and end point were set to the mentioned dates.

Additional input parameter settings are given in the table below.

Table 8. Selection of input parameters for flexibility estimation in Öland study case.

Parameter	Value	Unit
Nominal power factor - Wind power plants	1	-
Power factor limit - Wind power plants	0.95 (ind. or cap.)	-
Curtailment limit - Wind power plants	1	pu
Nominal power factor - Load	0.85 (ind)	-
Active power increase - Load	10	%

Different flexibility usage scenarios could then be tested by activating or deactivating the availability of the various flexibility types. When load flexibility was activated, it was assumed that an increased demand could be sustained for up to 2 consecutive hours and would then lead to a corresponding decrease in demand the following hours without that possibility to reactivate load flexibility for that time period.

2.1.3 Estimated power flows and bus voltage

Using the simulation inputs presented in section 2.1.2, the voltage and line loading of the study case feeder with the expanded wind power, but without any ANM solution or network reinforcement in place, were estimated. The results, seen in Figure 40, show a strong correlation between the voltage and line loading levels. It can also be seen that the voltages are well within the network limits, despite the increase in generation. The line loading exceeds the summer line rating on several occasions, highlighting the need to make investments to future-proof the local grid.

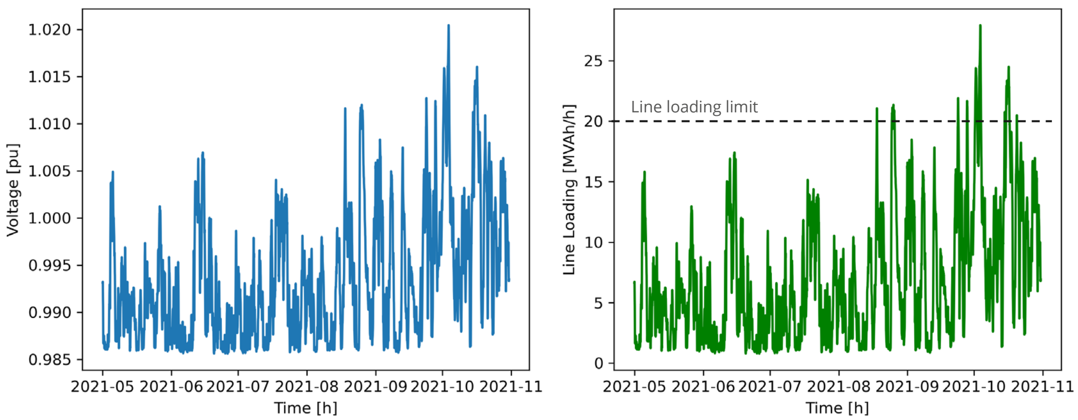

Figure 40. Bus voltage (left) and line loading (right) in flexibility simulation of Öland case.

2.1.4 Estimated flexibility usage

The results from a timeseries simulation of the ANM scenario of the Öland case, including the use of all three flexibility types, are shown in Table 9.

Table 9. Simulation results for Öland case flexibility estimation.

	Value	Unit
Study Time	2021-05-01 to 2021-10-31	-
Total flexibility usage duration	134	hours
Relative flexibility usage duration in studied time period	1.53	%
Total active power flexibility	256.1	MWh
Peak active power flexibility	8.3	MWh/h
Active power flexibility from WPPs	246.6	MWh
Peak active power flexibility from WPPs	8.1	MWh/h
Active power flexibility from loads	9.5	MWh
Peak active power flexibility from loads	0.2	MWh/h
Total reactive power flexibility	151.6	Mvarh
Peak reactive power flexibility	1.4	Mvarh/h

As seen in the previous table, implementing an ANM solution solely relying on reactive power and load flexibility would not be a sustainable option for the Öland case, as curtailment is the dominant type of flexibility used, despite being the least prioritised control option. While a considerable amount of reactive power is used for flexibility, the power factor adjustment constraints, limits the peak reactive power injections considerably. The duration of flexibility calls is however very limited, corresponding roughly to 6 days during the considered 6-month period.

Energy losses for the ANM scenario was estimated to 1297 MWh, or 1.83 % of the yearly transferred energy. The losses for the Grid scenario were estimated to 857 MWh or 1.21 % of the yearly transferred energy (note that the transferred energy differs slightly between the two scenarios due to the use of flexibility). The loss calculation only includes the line losses, as the transformer losses were assumed to be equal in both scenarios.

2.1.5 CBA

As mentioned in section 1.2.3, when comparing two alternatives one can exclude identical costs and revenues as these will cancel out in the comparison. For this study case the transformer needed to connect the 20 MVA wind power plant to the grid is needed for all cases and therefore excluded from the CBA. For this study case the issue can be solved by either using an ANM solution or solely by an investment in the grid. Doing nothing, or BAU, is not an option and the CBA therefore analyses two scenarios: the ANM and the Grid.

Table 10. CBA input data.

Scenario		ANM	Grid
Total investment cost during planning phase (million SEK)	ANM	0	-
	Grid	-	0
Total investment cost during construction/imple-mentation phase (million SEK)	ANM	1.5	-
	Grid	-	15
Estimated flexibility price (SEK/MWh)	ANM	565	-
Estimated yearly flexibility need (MWh)	ANM	256.1	-
Estimated yearly cost of energy loss (million SEK)		1.9	1.3
Connection fee (million SEK)	ANM	8.7	-
	Grid	-	10
First year of planning (20xx)		2023	2023
Total number of years spent in planning phase (x years)	ANM	4	-
	Grid	-	3
Total number of years spent in construction/imple-mentation phase (x years)	ANM	1	-
	Grid	-	2
Discount rate (%)		2.16%*	2.16%*
Regulated rate of return (%)		2.16%*	2.16%*

* E.ON Facts and Figures 2021 available at https://www.eon.com/content/dam/eon/eon-com/eon-com-assets/documents/investor-relations/en/presentations/210324_Facts_and_Figures_final.pdf

The ANM scenario consist of procuring flexibility from the wind power plant and from loads. Planning is assumed to begin in the year 2023 and is expected to last for four years although some of this time will be inactive due to long lead times related to the construction of the wind power plant. An option would be to set the starting year of the planning phase to later, however in this case we assume that some initial planning will take place at an early stage. The costs obtained during the planning phase is set to zero, assuming that for this case the planning costs are small and similar for both scenarios.

The construction and implementation phase is set to one year. Investment costs during the construction and implementation phase is set to 1.5 million SEK for the ANM solution. The cost is based on costs for pilot projects performed by E.ON.[12]

There are costs for purchasing flexibility that will occur during operation. The estimated flexibility price is set to 565 SEK/MWh and is based on the PEXA market index for PPAs in the Nordics on June 3rd, 2022, which was 54 EUR/MWh[13] plus 10 percent renumeration for wear and tear [58]. While wear and tear is more relevant for the wind power plant, the same price is assumed for all parties supplying flexibility. The amount of needed flexibility is set in absolute terms, meaning that the DSO will pay equally for up- and down regulation, and is obtained from the simulations, see Table 9.

As described in section 2.1.4 there are energy losses that should be taken into consideration. The cost for these is set to the average spot price for June 3rd, 2022, which was 140 EUR/MWh.[14] The estimated yearly cost of energy loss is 1.9 million SEK.

On the first year of operation, the DSO receives a connection fee payment from the wind power plant. The connection fee is set to total 8.7 million SEK, matching the investment cost of the ANM solution and the cost for procuring flexibility, and is paid in the first year of operation. I addition to the connection fee the DSO receives tariff payments as per the regulated income cap which is based on the costs outlined above.

The Grid scenario consist of one investment in the grid, a new overhead line. As for the ANM scenario, planning is assumed to begin in the year 2023 and is expected to last for three years. The costs obtained during the planning phase is set to zero, according to the same reasons as for the ANM scenario.

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[12] As per interview with Vladyslav Milshyn at E.ON in June 2nd, 2022.

[13] Exchange rate: 1 EUR = 10.45 SEK, as per June 3rd, 2022.

[14] Average spot price for SE4, Sweden on June 3rd, 2022: 140 EUR/MWh. For the EUR/SEK exchange rate, see footnote 13. As the spot price is volatile, a sensitivity analysis of how a change in the spot price affects the NPV is carried out and presented in the appendix.

The construction and implementation phase is set to two years. Investment costs during the construction and implementation costs is set to 15 million SEK and mirrors the costs for the new overhead line.

Also in this scenario, the energy loss is considered, and the cost is calculated based on the information in section 2.1.4 and a sport price, see footnote 14. The estimated yearly cost of energy loss is 1.3 million SEK.

On the first year of operation, the DSO receives a connection fee payment from the wind power plant. The connection fee is set to total 10 million SEK matching 2/3 of the investment cost for the new overhead line which correspond to the utilisation rate for the new wind power plant. Just as in the ANM scenario, the DSO also receives tariff payments as per the regulated income cap which is based on the costs outlined above.

The discount rate and the regulated rate of return is set to the weighted average cost of capital for both scenarios.

The results for both scenarios are positive NPVs. Meaning that the DSO will profit from the investment regardless which they choose. However, the Grid scenario generates an NPV of 5.1 million SEK compared to 6.3 million SEK for the ANM scenario indicating that the DSO from a commercial perspective should choose the solution presented in the ANM scenario. A reason why the ANM scenario has a higher NPV is that the investment cost for the Grid scenario is taken in the first years while most of the cost for the ANM scenario will be a running cost. Furthermore, the connection fee for the ANM scenario is relatively large compared to the investment cost while the opposite is true for the Grid scenario.

The present value of costs is slightly lower in the ANM scenario than in the Grid scenario: 64.4 million SEK compared to 68.4 million SEK, see Table 11. If the estimated cost for energy losses is excluded the difference between the scenarios is larger since the overhead lines for the ANM scenario has a higher utilisation rate resulting in higher energy losses. A reason why the Grid scenario has a higher cost is the operational and management cost that depends on the investment cost which is higher for the Grid scenario and that the investment cost for the Grid scenario is taken in the first years while most of the cost for the ANM scenario will be a running cost.

For a more detailed description of how different parameters affect the result see the appendix.

Table 11. CBA results.

Scenario	Project type	NPV (million SEK)	Present value of costs (million SEK)	Present value of costs excluding energy losses (million SEK)
ANM	ANM	6.3	64.4	12.6
Grid	Grid	5.1	68.4	34.1

2.1.6 KPIs for Öland case

As seen in Table 12, the KPIs for the technical part of the study case (1-3) are similar for the two future scenarios, which is due to that the increase in installed wind power capacity was a prerequisite for the study. However, the average line loading is considerably higher in the ANM scenario, meaning an increase in grid utilisation compared to the reinforcement strategy.

Table 12. KPIs for the Öland case study.

KPI number	**1**	**2**	**3**	**5**
KPI description	Average line loading	Permitted installed new generation capacity	Increased electricity production from renewables	Deferred network expansion costs
ANM	40.5 %	20 MW	57.4 GWh/year	6 % resp. 63 %[15]
Grid	23.8 %	20 MW	57.7 GWh/year	N/A

[15] Calculated based on Present value of costs in Table 4. 6 % is for when energy losses is included and 63 % when they are excluded.

3 OPTIMISATION OF FLEXIBILITY IN SHORT-TERM PLANNING

Short-term planning gives the DSO a tool to predict operational conditions on an inter- or intra-day basis. This planning aspect is becoming increasingly important, as the power injections from renewable energy resources cab vary rapidly. The short time frame considered in this planning stage allows for the use of weather forecasts to model renewable production with high temporal and spatial granularity. With access to accurate estimations of load and generation profiles and a network simulation model, load flow computations yield the predicted operating conditions. Combining this information with the ANM algorithms in iterated load flow simulations will give an estimate of the flexibility usage. The estimated operating conditions can also be used to dispatch set points directly to generators and other flexibility resources in advance, which makes optimising the distribution of set points an attractive option.

3.1 Optimal power flow and ANM algorithms

Optimal power flow (OFP) is an increasingly popular optimization method that is used to compute set points so that operational costs are minimised under some given network constraints [59]. Considered costs can be related to e.g., flexibility usage or energy losses. Several OPF formulations exist, as well as a large number of solving techniques that are applied to guarantee convergence to an optimal solution. In general, solving such optimisation problems are computationally intensive which typically restricts simulations to load flow snap shots with hourly or minutely intervals, and that in turn yields a lower set point update frequency [60]. This combined network model dependence and delay in set point updates makes discrepancies between predicted and actual network operating conditions unavoidable. Thus, using stand-alone OPF methods does not guarantee operation within network constraints. However, when combined with an ANM solution that operates in near-real time, undesirable set points resulting from an OPF modelling error will be corrected by the ANM control feedback loop, eliminating unwanted operating conditions. In the simplest form, an OPF-based short-term planning method can be implemented independently from a centralised ANM algorithm. A potential performance-enhancing measure would be to coordinate the distribution of flexibility prescribed by the OPF computation, and the flexibility dispatch used by the centralised ANM algorithms. By transferring the most cost-effective distribution of flexibility to the ANM algorithm, short-term planning and operation could be executed in a more coherent manner.

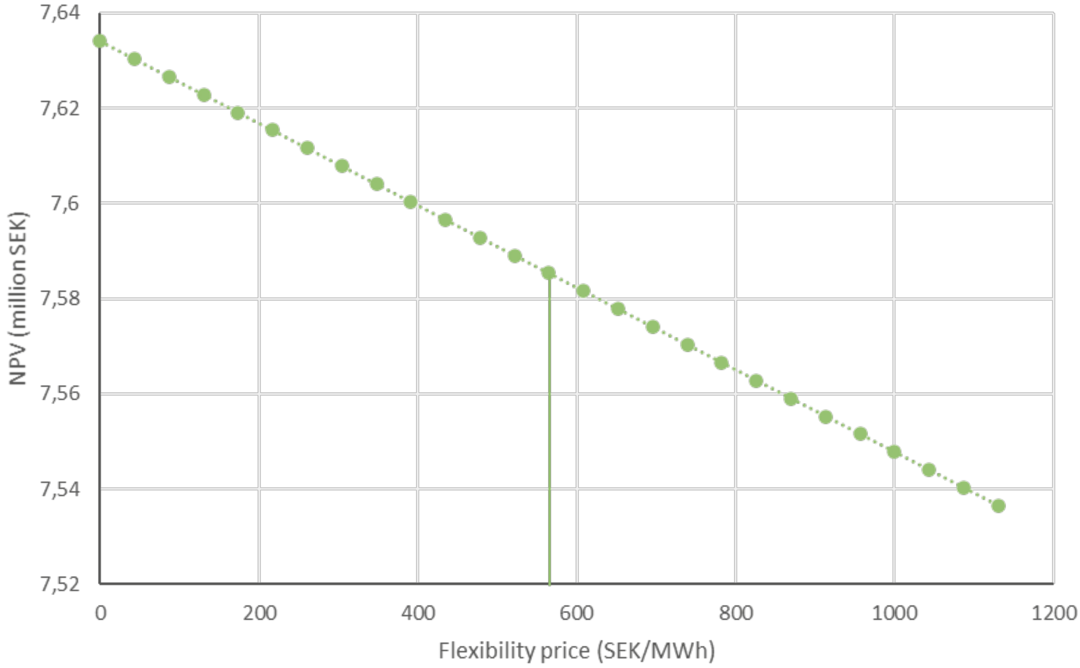
4 DISCUSSION

The outcome from technical part of the long-term planning method has certain caveats, which are ultimately due to the uncertainties built into the method. These uncertainties can be divided into two categories, data-driven and model-driven. The former is related to the estimation of load and generation profiles, while the latter includes simplifications in the network modelling, as well as assumptions on availability of flexibility and other input parameters. By applying the method to an historic case, in which simulations could be compared to actual data, it would be possible to thoroughly evaluate the impact of the mentioned uncertainties.

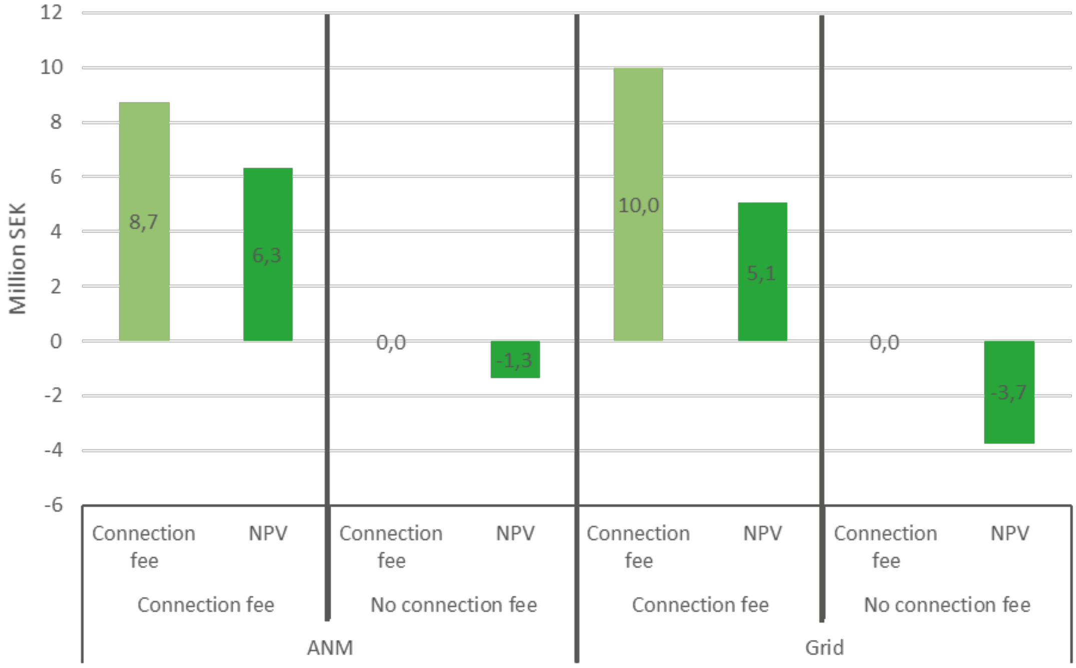
As mentioned, there are both pros and cons with the CBA model and its current design and there is room for improvement. It would for example be beneficial to be able to use an ANM solution as a temporary solution to later be replaced by a grid extension. The results are heavily dependent on the assumptions made by the user, and one can therefore also consider to incorporate an automatic sensitivity analysis for certain variables.

APPENDIX

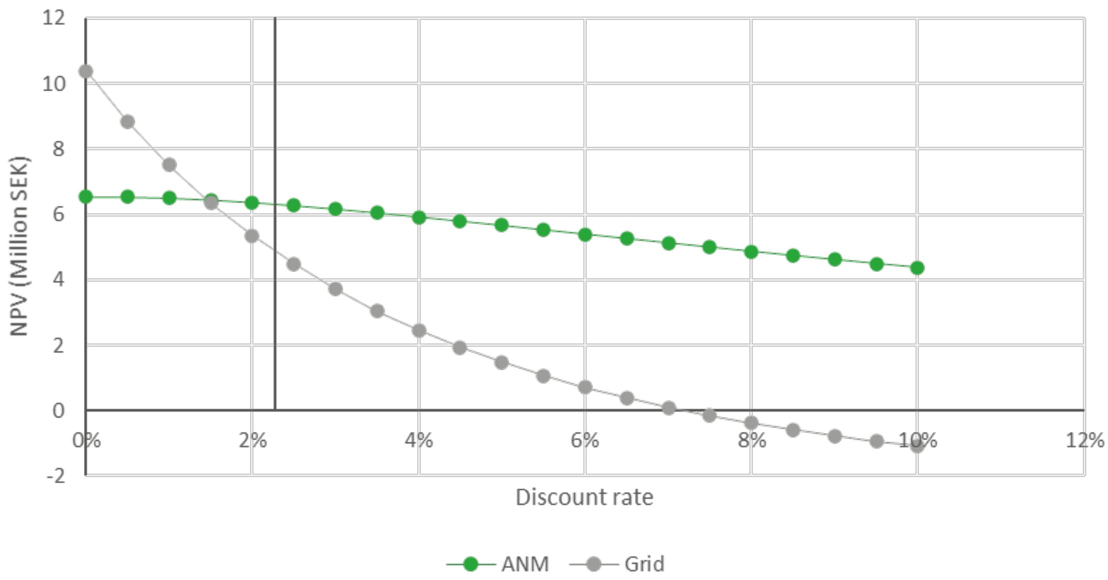
Sensitivity analysis



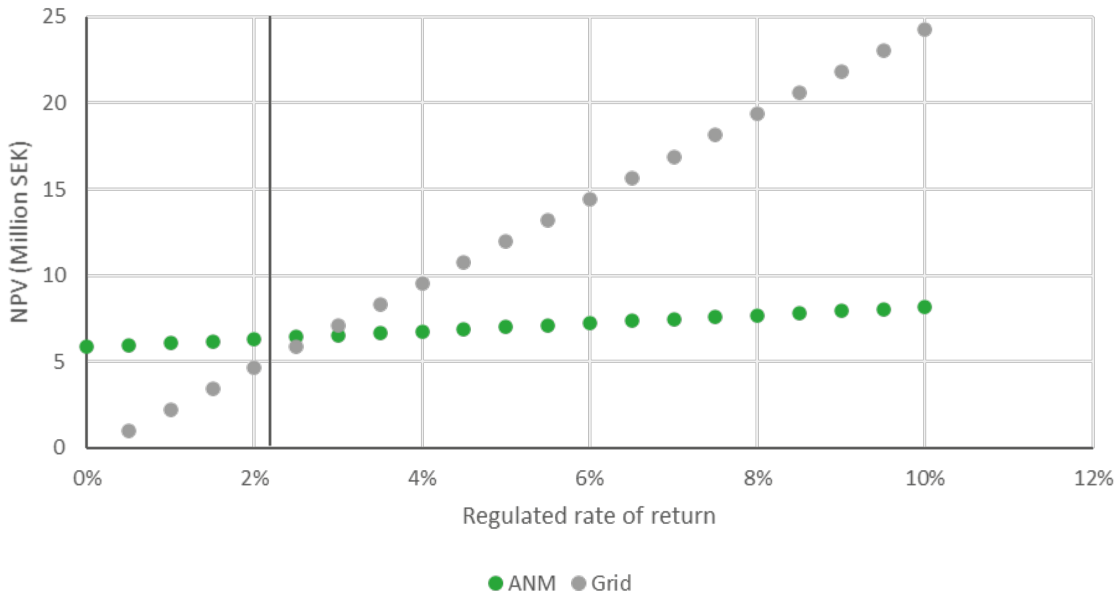
Assuming that the flexibility price is constant it has a negative linear effect on the NPV. Costs for energy loss are greater than the cost for flexibility, hence the effect of a higher flexibility price is limited. However, if the flexibility price were to unexpectedly increase over time during operation, it would have an even more negative effect on the NPV as the operational costs and thus the revenue would be based on the (lower) expected price. In reality the expected operation costs would be updated every fourth year when the DSO reapplies for their revenue cap, this is however not captured in this model as it would not fulfil the requirement of few and simple input variables.



The connection fee is important for the profitability of the project, considering that if the DSO is unable to obtain a connection fee for any investment, regardless of project type, it will not be profitable. This is due to that the DSO takes on investment costs early in the project while the income is spread out over a long period of time, thereby being discounted and not as valuable.



The discount rate mirrors present value of future cash flows in a discounted cash flow analysis, which this CBA is. When the discount rate is low the value of the future cash flow is equal to that of today, when the discount rate is high the value of the future cash flow is lesser than that of today. It is not straightforward to know what a proper discount rate is, however, when performing a financial CBA is it custom to use the weighted average rate of capital as discount rate. The sensitivity analysis shows that the NPV is very dependent on the choice of discount rate when investments are large and not evenly distributed over time. Here, a large share of the costs in the grid case burden the DSO at an early stage while the income is spread out over the lifespan of the investment. With a high discount rate, the revenues are therefore less valued than the costs.



The NPV increase as the regulated rate of return (ROR) increase. This is natural as the ROR regulates the size of the revenue cap – the higher the rate of return the higher the revenue. The slope of the NPV is steeper for the Grid than for the ANM because the return is based on the value of the asset base and the asset base is larger for Grid than for ANM. This is how the current regulation promote heavy investment in infrastructure rather than ANM solutions and change in operation that does not require heavy investments.

CHAPTER 6: OVERVIEW OF TECHNICAL ASPECTS OF ANM

(ANM4L DELIVERABLE D3.3)

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1 TECHNICAL VIEW ON DISTRIBUTION GRID DEVELOPMENT

Key takeaways:

- **The worst-case scenario approach to network development restricts the integration of renewable energy sources.**
- **Grid utilisation can be increased by shifting focus to more flexibility in network operation.**

Present distribution networks are generally designed to supply consumers with electricity. This is a consequence of the geospatial separation of the load centres and the large power plants supplying them. However, the increasing presence of renewable distributed generation allows for a mixing of electricity demand and production on a local and regional level. This is a disruptive change of the system, which combined with a projected increase in demand, driven by the electrification of the industry and transport sector, poses a significant challenge for the distribution network operators (DSOs) that are tasked with operating the grid.

A DSO must ensure that electrical energy safely and reliably can be transferred from producers to consumers. In addition, operation should be efficient and cost-effective. The present design paradigm for distribution networks is based on management of expected worst-case operational scenarios. Under normal operating conditions this amounts to maintaining network voltages and currents within prescribed limits, as well as fulfilling other power quality requirements including restrictions on the flow of reactive power to the transmission network. Common practice is to eliminate such issues primarily in the long-term grid planning process through infrastructure upgrades. This approach is well-adapted to distribution networks with only loads present, as the DSO then only needs to consider unidirectional power flows in radial feeders and decreasing network voltages at high loading levels. With the introduction of distributed generation, two significant disadvantages with the conventional view on network development can be observed.

- The worst-case scenario design criterion is ill-suited for the highly variable production patterns of renewable energy sources.
- The use of network reinforcement to ensure safe and reliable network operation is an inflexible and slow option for managing the large-scale integration of distributed energy resources.

The first point can be illustrated by a typical duration curve for electricity generation from renewable sources, see Figure 41 . The steepness of the curve means that if large amounts of renewable generators are present in the system (which would then determine the worst-case constraints), the conventional network design approach results in construction of grids with significant overcapacity during most time of the year. While this overcapacity permits easy connection of additional resources, the fast pace of the renewable energy transition, in combination with the equally fast electrification of transports, increases planning uncertainty and greatly complicates infrastructure investment decision-making as there is an increased risk for costly and ill-timed network upgrades resulting in low grid utilisation. As indicated by the second point, network reinforcement is often slow, which limits the speed of the connection process for new renewable generation, thus creating a bottleneck in the transition to clean energy.

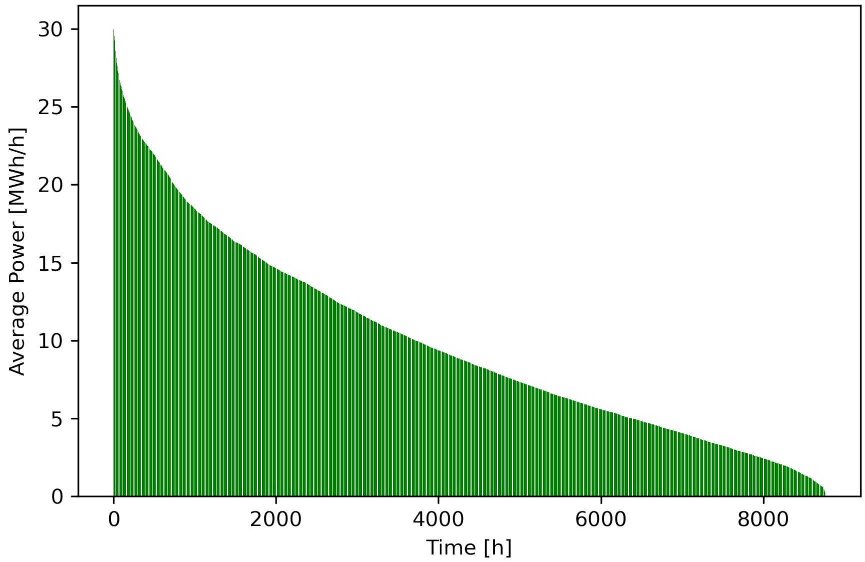

Figure 41. Duration curve for a 30 MW wind farm. Hourly production data for one year are reordered in decreasing magnitude.

However, by shifting the focus from long-term planning to operational flexibility when addressing grid capacity issues, the network development process becomes more dynamic and better matches the rapidly evolving energy landscape. Active network management (ANM) is one such concept and involves the use of more extensive network monitoring and control of grid-connected energy resources than the currently prescribed. With ANM, the need for infrastructure upgrades can potentially be deferred while new distributed generation can be connected without delays. To facilitate a change in network development practices, new operational strategies must be developed, and their reliability proven. Furthermore, it should be possible to evaluate the impact of the new methods at a long-term planning stage to assist investment decision making.

2 ACTIVE NETWORK MANAGEMENT IN THE ANM4L PROJECT

Key takeaways:

- **ANM algorithms for limitation of overvoltage, congestion and reactive power management have been developed. Their performance has been demonstrated and evaluated in simulations, using test systems and real network models.**
- **The ANM algorithms allow for increased penetration of renewables by safely reducing operational margins. Using centralized control, the set-up is independent from choice of financial solution, meaning the flexibility dispatching can be adapted to a wide range of legal and economic frameworks.**
- **The algorithms are included in a toolbox for operation and short-term planning.**
- **A method for estimating of flexibility usage in long-term planning scenarios has been developed. It allows for quantification of financial risk without the need for detailed simulations.**

The technical part of the Active Network Management for ALL (ANM4L) project is centred around the development and demonstration of ANM tools in a European context. Within the project, a technical definition of ANM has been given [61]:

ANM is the exploitation of flexible network assets for the purpose of providing secure means of increasing grid utilisation.

Development of control algorithms for ANM purposes has been conducted within work package 3 (WP3). The results from WP3 are summarised in this report. Modelling of the ANM algorithms for network planning was also addressed in the work package. A key project goal is to create an ICT toolbox that enables integration of ANM planning and operation with interfaces to both DSOs and flexibility providers (ANM4L joint proposal). The toolbox is developed within WP2, but aspects related to the integration of the ANM algorithms are also discussed in this report. Finally, some comments are provided on the results of the demonstrations of the deployment process of the proposed ANM solution in Swedish and Hungarian contexts, which are carried out and validated in WP 5 & 6.

2.1 Control algorithms

To increase the amount of renewable generation in the system, an ANM control algorithm should mitigate any issues resulting from large local power production. With this in mind, three control objectives were considered during the development of the algorithms: congestion management, mitigation of overvoltage, and reactive power control. The first two objectives are directly related to distribution network operational requirements. The third objective has relevance when considering the power flows at the TSO-DSO interface. The developed ANM methodology prescribes maximisation of grid utilisation through safe reduction of operational margins, which stand in contrast to the standard worst-case scenario approach to network development. The ANM controllers are therefore instructed to only act if a predetermined threshold value is crossed (typically a given voltage or thermal limit).

In Chapter 2, the following algorithms are presented:

1. Local voltage limitation algorithm for renewable generation.
2. Local voltage limitation algorithm for loads.
3. Congestion management algorithm for renewable generation and loads.
4. Reactive power management algorithm for renewable generation.
5. Combined local voltage limitation and congestion management for renewable generation and loads.

In [62], the following algorithm is presented:

6. Combined congestion and reactive power management algorithm for renewable generation and loads.

In algorithms 1 and 6, active and reactive power is controlled. In algorithms 2, 3 and 5, only active power is controlled, while in algorithm 4 only reactive power is controlled.

2.2 Implementation

In this section, some key implementational aspects of the ANM algorithms are presented. For a detailed view of the algorithms, see references in section 2.1. The task of the control algorithms is to maintain network operational safety and reliability. Since DSOs are performing short-term network planning (hours-days) to predict potential operational states, the ANM algorithms should also be applicable in that context. Finally, as ANM should be seen as an alternative to conventional grid reinforcement, it must be possible to evaluate it against other investment strategies, and the impact of the algorithms should then be approximated from a long-term planning perspective.

2.2.1 Network operation

- PI controller updates active and/or reactive power control set points online in short time steps (~a few seconds). Process can be automated if there are enough flexibility resources to mitigate any constraint violations [3].
- Implications of multiple uncoordinated controllers for local voltage control using active and reactive power in a test system have been studied and feasible operational stability criteria have been derived [63].

- With centralized control, communication between central controller and grid assets is required. For congestion management and reactive power control, centralized control is a requirement [62].

- Local control algorithm is independent of network model (plug-and play solution). Centralized control requires network model to allocate flexibility to correct resources (process can be done offline a-priori). As a minimum, the network model must include network topology.

- The algorithms are included in a Python package for use in the ANM4L toolbox. This provides flexibility with respect to specific operational environments and increased modularity which facilitates further algorithm development and adjustments. For more details, see [64].

2.2.2 Short-term planning

- DSOs use short time planning to select adequate operational strategies. Detailed modelling is required to achieve high precision assessments of operational conditions.

- Through simulations of ANM algorithms in operation, the flexibility usage for an expected operational scenario can be estimated.

- Repeated load flow computations together with load and generation profiles are used to simulate the algorithms in operation.

- The ANM4L toolbox includes a planning feature which provides an interface to DSO power system simulation software [64].

- The quality of the forecasted flexibility usage ultimately depends on the accuracy of the network model and the predicted load and generation profiles.

- Using centralized control, the flexibility dispatching process is independent from the controller, meaning flexibility can be freely distributed among available resources. This allows for equal sharing of control actions, implementation of a local flexibility market, or other contractual arrangements suited for a specific deployment environment.

- Determining power injection set points through an optimization procedure is suitable for the short-term planning phase. Combined with an ANM solution in operation, this can potentially reduce the total flexibility need, while any prediction errors are corrected by the real-time ANM algorithm.

2.2.3 Long-term planning

- DSOs use long-term planning (months-years) for support in investment decision making. The longer time perspective means predictions are reliant on data of lower granularity. At the same time, assessment is widened with the inclusion of additional economic and legal parameters.

- In the long-term perspective, an ANM solution should be evaluated against alternative investment strategies. Estimating the flexibility need on a long-term basis is key to determining the operational cost of an ANM solution.

- Simulations of real-time operation is computationally intensive given the short controller sampling intervals. A simplified flexibility estimation was developed to significantly reduce the computational burden.

- The long-term flexibility usage estimation method applies power and voltage distribution factors that generate approximate linearized power flow results.

- The ANM algorithms are in this stage modelled implicitly; during simulated network constraint violations, the accumulated difference between the simulated values and the maximum allowed network values is considered to be equal to the flexibility usage. This assumes fast and stable operation of the ANM controllers.

- The advantage of the simplified flexibility usage forecasting is that the investment costs, as well as the operational costs, for ANM solutions can be estimated quickly. The financial risks can be quantified without the need for full simulation of the control dynamics, or even power flow computations, and the estimated costs can transparently be evaluated against conventional solutions.

2.2.4 Performance evaluation

Within WP3, the performance of the developed algorithms was primarily assessed on a theoretical/computational level. First, two network test systems were used to investigate the control dynamics in MV and LV networks, respectively. While the controller configuration is independent from the voltage level, other differences between MV and LV networks, such as the R/X ratio; the increased prevalence of congestion near HV/MV transformers; and voltage issues primarily occurring at the end of LV feeders, warranted a detailed investigation simultaneously on multiple distribution network voltage levels.

Operation/short-term planning using algorithms 1-6 in section 2.1 was successfully implemented in different configurations of the following test systems

- CIGRE European MV benchmark [21] in DigSILENT PowerFactory.
- 5-bus radial LV feeder [65] in MATLAB/Simulink.

Synthetic load and generation profiles were used to trigger control response and study operation under unfavourable conditions. Examples of the algorithm performance using the above test systems are found in Chapter 2.

Furthermore, it was demonstrated in a LV model of two actual feeders in Southern Sweden that the voltage limitation algorithm could be applied for use in a battery energy storage system to mitigate overvoltage caused by local PV generation, [66].

In collaboration with WP2, the algorithms were transferred to the ANM toolbox and the performance in a simulated environment was validated using the DPsim software for power flow computations on the CIGRE MV test system.

In collaboration with WP5, the performance of the voltage limitation and congestion management algorithms (algorithms 1 & 6) were validated in a network model representing the LV demonstration site at Öland. It was concluded through simulations that the risk for network constraint violations was negligible and stricter operational limits were therefore imposed in order to verify the expected performance. A successful implementation of the congestion management algorithm in simulations of the Öland MV network were also made. This formed the basis for the long-term planning use case for Öland, in which a yearly flexibility usage estimation was obtained. This example, together with the subsequent cost-benefit analysis for the Öland MV case is found in Chapter 5.

Finally, as the proposed ANM methodology prescribes maximisation of grid utilisation with minimal infrastructure upgrades, there is clearly room for optimization of flexibility usage under more favourable assumptions on controllability of the system. This aspect was investigated in a master thesis project [67], where it was concluded that for local voltage management that optimal use of reactive power would lower the required curtailment of renewables in the studied scenarios. For congestion management, the performance of the ANM algorithm relative to the optimal allocation of flexibility with respect to minimization of curtailment is largely dependent on the choice of dispatching method.

3 KEY PERFORMANCE INDICATORS

Key takeaways:

- **ANM algorithms eliminate all operational risks related to expansion of distributed generation. This includes the three control objectives for voltage, congestion, and reactive power management.**
- **This permits infinite installed generation capacity, while energy production will be bounded by curtailment to maintain safe network operation.**

The three key performance indicators (KPIs) assigned to WP3 in the ANM4L project are

- KPI 1: Loading of key transformer(s) or line(s).
- KPI 2: Increased installed capacity of (renewable) distributed generation.
- KPI 3: Increased electric energy produced by (renewable) distributed generation.

The KPIs are described in more detail in [55].

KPI 1 is closely related to the goal to maximise utilization of existing network equipment. As shown in e.g., Chapter 2, the ANM algorithms are only active at the very edge of the operational range, and therefore permits loading scenarios which would otherwise require capacity increases through network reinforcement. The elimination of operational margins also leads to higher average loading (i.e., increase in utilisation) of existing components. This concept was demonstrated in the Öland MV simulation case, where the use of ANM solution led to higher average loading of an existing overhead line.

KPI 2 was also investigated in connection to the Öland MV case, and it was shown that an ANM scenario and grid expansion scenario would allow the same amount of new installed capacity, while the reduction in total yearly energy in the first scenario (due to curtailment) compared to the second one was less than 1 % for the specific case (KPI 3).

The results from the case study give an example of the general characteristics of the ANM algorithms with respect to KPI 2 & 3. Given stable operation and adequate access to flexibility resources, the operational risks are eliminated, and an infinite amount of generation capacity can then be connected without any of the three control objectives being violated. The concept is illustrated in the figure below. A clear limit to the energy production is seen, which is ultimately determined by the finite capacity of the existing network. To maintain safe operation within the network limits, the ANM algorithms will simply increase curtailment.

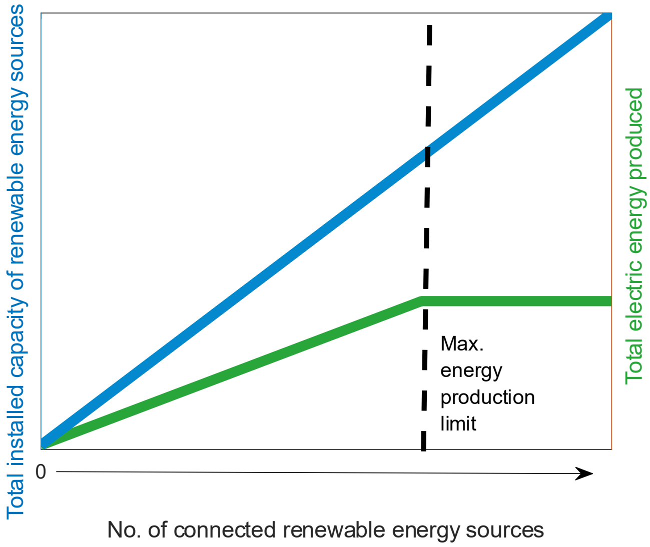

Figure 42. Conceptual visualisation of production and capacity improvements with ANM in a distribution network.

4 WIDENING THE SCOPE

Key takeaways:

- **The modular nature of the ANM algorithms simplifies additional development. Future work can extend the application to management of network issues related to excessive loading.**
- **Other topics suitable for further development are centralized voltage limitation and optimization for minimization of curtailment, losses, and operational costs.**

The general framework of the ANM algorithms gives the opportunity to further explore their use in distribution networks. Throughout the project, several paths for future development of the work were identified. These can be broadly classified as follows:

- Algorithm development
- Application and deployment aspects

Algorithm development

Considering the modular nature of the ANM algorithms, combining them into new configurations with additional features is relatively straightforward as only a bridging code needs to be added to avoid counteracting control actions. The natural extension to the presented algorithms would be to combine algorithms 5 and 6 to fully integrate all three main control objectives into one algorithm. Furthermore, assuming access to communications with flexibility resources, a centralised voltage control algorithm is also feasible. The voltage limitation problem is inherently local in the sense that flexibility usage near the overvoltage location is more effective than using resources further away. In contrast to the congestion management case, this location-dependent flexibility may not be suitable for trade on an open flexibility market. On the other hand, coordinating voltage control actions may reduce the need for curtailment.

Optimising the flexibility dispatch for congestion management was not the focus in WP3 but it is another topic fit for further development due to the potential reduction of operational costs. Estimation of network losses due to increased grid utilisation should also be considered in future work.

Application and deployment aspects

Extending the operating range of the ANM controllers to manage issues caused by excessive loading, such as undervoltage or congestion, is highly relevant given the rapid electrification of transportation. The existing voltage algorithms would only need minor updates, such as changing the input limits so that flexibility will be dispatched to increase the voltage [68]. For congestion management, the power flow direction would also have to be tracked so the cause of the congestion is identified.

Initial investigations on the use the ANM algorithms for EV charging flexibility, as well with household battery systems, have been made within the project [66], [69]. Early results indicate that the algorithms indeed perform as expected.

The impact of active distribution networks, and specifically the ANM algorithms, on the overlying transmission network has been studied [68] and potential positive effects was identified. Further investigation into the interactions between distribution and transmission networks in the presence of ANM is highly relevant.

5 CONCLUSIONS

Key takeaways:

- **Full voltage and current range used → no margins needed.**
- **Smart inverters can implement local voltage controllers. Local voltage controllers operate without instability.**
- **Flexibility dispatch can be ordered by bids, efficiency, fairness, or other custom arrangements.**
- **<u>Operational risk</u> for limit violations is zero; <u>financial risk</u> of flexibility can be quantified without simulations in power system software.**
- **Voltage, congestion, and reactive power management can be combined.**

The ANM algorithms are intended to be easily deployable, scalable, and adaptable to different networks and therefore simplicity was favoured over optimality in the development process. The algorithms are derived from a basic structure, which includes a PI controller and an input signal that is computed from limit values rather than a reference value. It is then possible to safely operate the network within voltage and current limits and operational margins are no longer needed. The reliability of the algorithms has been demonstrated in simulations in models of synthetic and real distribution networks. Additionally, criteria for stable control dynamics have been derived for multiple uncoordinated local voltage controllers in an(y) arbitrary radial distribution network.

As the operational risk for limit violation becomes zero, as described in Chapter 2, grid utilisation can be maximised. Flexibility can be controlled locally or centrally. The first case is suitable for plug-and-play deployment using smart inverters for voltage limitation. In the latter case, flexibility dispatch is ordered by bids, efficiency, fairness, or other arbitrary arrangements. This is facilitated by the modular structure of the algorithms, in which the dispatch process is separated from the ANM controller.

In preparation for a fully deployable ANM solution, a long-term planning methodology was developed that lets the user estimate the flexibility usage in future development scenarios. Specifically, the financial risks related to the cost of flexibility can be quantified without the need for computationally expensive iterated power flow simulations. This provides a foundation for making fast and transparent comparisons between different network investment strategies.

The ANM algorithms are designed with three control objectives in mind: congestion management, mitigation of overvoltage, and reactive power management. These objectives can be combined, and several combined algorithms have been presented within the project.

SUMMARY

As ANM is depending on the external control of various flexible network assets, it is important to assess the needs, capabilities, limitations, and costs of different type of assets. **Categorisation of flexible network assets** provide important information in the development and deployment of ANM solutions. Similarly, activation of ANM based control can be distributed among of the flexible network assets located in a part of the network where it is possible to influence and support the specific grid need. Selection of assets can be made based on technical and/or economic efficiency, as well as on other factors such as fairness. **Setting up a flexibility dispatch list**, all relevant flexible network assets can be made available to contribute according to the selected preference

The results of the ANM4L project successfully show the values which ANM solutions brings, highlighting the importance to **Use ANM to keep up the pace of the energy transition**. Considering the urgency of the energy transition, the lead times associated with infrastructure projects are detrimental. It is important to realize that ANM offers a faster way to accept new RES connections. If physical grid reinforcement is still preferred, ANM should be used to permit RES connections while waiting for this to happen.

There are several barriers to overcome to deploy ANM methods on a large scale. In order for DSOs to better utilise alternative solutions and flexibility services, changes in the method of economic incentive regulation are necessary. **Introduction of a total expenditure approach (TOTEX)** could remove the separate treatment of operational and capital expenditure. **Standardised communication, software modularity, and interoperability** are solution supporting integration and maintenance of ANM tools in DSO planning and operation environments. **Requirements in grid codes** could standardise implementation of local ANM controllers in smart inverters.

ANM brings a paradigm shift regarding risk considerations for operation and planning of distribution grids, going into **full utilization of grid capacity by removing safety margins.** ANM enables use of the full grid capacity with respect to voltage limits and current limitations in terms of fixed or dynamic ratings, by relying on real-time control. Thus, from the grid operator perspective **the amount of RES that can be safely connected is unlimited**, where the operational risk for damaging limit violations is zero. However, **relying on curtailment or other flexibility increases the financial risk.** As more RES is connected, the need for temporary curtailment or flexibility services rises, and with this the uncertainty of costs for procuring flexibility in the long-term.

The future energy system will be an integrated system-of-systems, combining values of different energy carriers and sectors. Flexibility solutions are key enablers to manage a 100% fossil-free system in a sustainable and resilient manner, and grid operators need solutions to handle such complex system. The ANM4L project has successfully shown the values which ANM solutions brings to meet the flexibility needs of DSOs for both operational and planning.

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