Framework and methodology for active distribution grid planning in Norway

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***Abstract*—The long-term planning frameworks currently used by electricity distribution grid companies are not designed to account for new challenges such as variable distributed generation or for new opportunities of active grid measures. Various advanced optimization methods for active grid measures are presented in the research literature, but they are rarely used in practice and are not always well suited to informing decision processes in distribution grid planning. To bridge this gap, this paper presents a framework for active distribution grid planning that takes as a starting point the traditional planning framework commonly used by Norwegian grid companies. The framework with selected, probabilistic methodologies is demonstrated through a case study considering voltage problems due to distributed photovoltaic (PV) generation, and battery energy storage systems and PV curtailment as active measures to defer grid reinforcement. The paper moreover discusses how probabilistic approaches can contribute to better informed distribution grid planning decisions.**

Keywords—power system planning, socio-economic cost-benefit analysis, risk analysis, flexible resources

I. Introduction

Electricity distribution grids are being challenged by greater variability in operating conditions and new uncertainties due to e.g. distributed generation (DG) from variable renewable energy (VRE) sources and electrification of transportation. At the same time, new opportunities of *active* distribution grid operation are becoming available that may mitigate some of the challenges by modifying load, generation and power flow during operation. Examples include battery energy storage systems (BESS) in the grid, reconfiguration of the grid, and flexible resources at the demand side (flexible loads) or the supply side (flexible DG). Implementing and relying on such measures taken during operation can be considered as *active* measures in the long-term planning of the distribution grid and may complement traditional ("*passive*") measures such as grid reinforcement.

It has been well described by the CIGRÉ C6.19 Working Group [1] and others how these challenges and new potential measures call for new, probabilistic methodologies for optimal distribution grid planning. Traditionally, planning approaches are deterministic, and probabilistic methods and approaches have only to a very limited extent been used in practice. A recent survey of Norwegian electricity distribution grid companies carried out by some of the authors reaffirms this picture. In the research literature, on the other hand, a multitude of advanced optimisation methods have been proposed. However, considering BESS as one example of an active measure, a recent survey of the literature [2] found that these methods were rarely applied in a practical, long-term grid planning perspective. This makes it more challenging for distribution grid companies to employ such methods to assess costs, benefits and risks of active grid planning measures.

To contribute to closing this gap between current practice and the scientific state of the art, we present here a framework for active distribution grid planning based on the traditional planning framework commonly used by Norwegian distribution grid companies [3]. The traditional framework has previously been described and extended in [4, 5], and we also build upon the work of the CIGRÉ WG C6.19 [1]. The objective has been to combine the new elements from active distribution grid planning into a framework that the grid companies are familiar with and that is adapted to Norwegian conditions. In this paper we consider BESS as one example of an active grid measure, and we will demonstrate the application of the framework with appropriately selected methodology on a simple and illustrative but realistic case.

The main contributions of this work are twofold: 1) It proposes a comprehensive framework for active distribution grid planning and moreover describes, demonstrates and discusses how it can be applied in practice. 2) The methodology that is incorporated for the case study demonstration extends a previously presented multi-period optimal power flow (MPOPF) model for operational planning [6] to applications for long-term grid planning. In the present work it is employed to emulate how an active grid planning measure affects the operation of the distribution system and to estimate the operational benefits, accounting for short- to long-term variability and uncertainty of load and generation. In contrast to much of the existing literature [2], this work does not focus on the (static) problems of BESS sizing and siting, but rather considers BESS jointly with other measures in a long-term grid planning perspective and focuses on describing risks associated with grid planning alternatives.

The rest of the paper is organized as follows. The proposed framework for active distribution grid planning is first briefly presented in general in Section II. The framework is then demonstrated in Section III by applying it to a case with a concrete planning problem for a Norwegian distribution grid. Here each step of the framework, including the methodology employed, is described in more detail for the particular case. A broader perspective is then taken in Section IV, which concludes the paper by discussing other applications and implications of the framework and of probabilistic grid planning approaches more generally.

II. Framework for Active Distribution Grid Planning

Norwegian distribution grid companies commonly follow the framework and process for long-term grid planning described in [3–5]. The proposed framework is augmented with more detailed modelling of the variability and uncertainty in load and generation, the inclusion of active grid planning measures, and probabilistic and multi-criteria analysis of the measures. These extensions have similarities with previously presented frameworks for active grid planning [1, 7, 8] but has several distinctions: We treat active and

DOI of published version: 10.1109/PMAPS47429.2020.9183711

passive measures on equal terms, we distinguish between active measures in the grid and with end-users, we consider that the types of technical analyses will depend on the case, we emphasize the iterative nature of the planning process, and we emphasize the socio-economic planning criterion that Norwegian grid companies are required to follow. The planning process according to this framework is structured in seven steps and illustrated in Fig. 1. For each of the steps, a brief outline is given below before its application is described and exemplified in more detail in Sec. III.

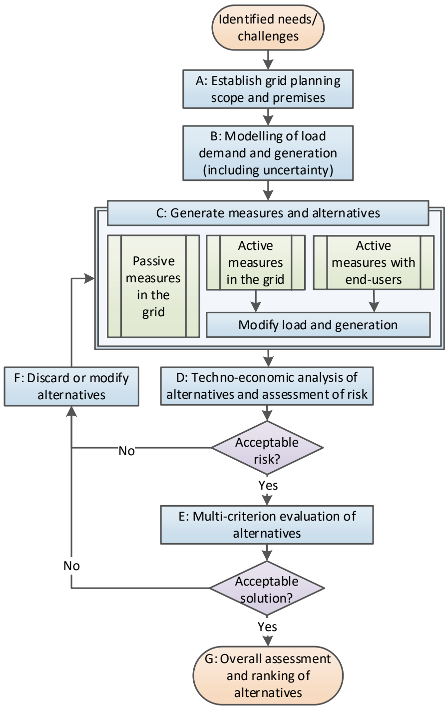

Fig. 1. Schematic grid planning process in the proposed framework.

Step A: Establishing grid planning scope and premises. A grid planning process is typically triggered by an identified need, related to problems in the existing grid or that the grid is expected to face in the future. This need sets the premises and scope of the grid planning problem, including the planning objective and criteria, system boundaries, existing plans, and the analysis horizon. The premises also include regulatory restrictions and policies concerning technical and economic risk that may be specific to each grid company.

Step B: Modelling of load demand and generation (including uncertainty). Grid planning has traditionally been taking a deterministic approach to load and generation modelling, e.g. only considering a worst-case operating state or a single daily profile. The probabilistic framework proposed here involves developing models for variation and uncertainty of load and generation both i) within each day and ii) within the year, as well as iii) prognoses for the long-term development in these quantities over the analysis horizon. Furthermore, active grid planning measures that rely on actions taken during operation makes it necessary to explicitly capture time dependences on operational time scales.

Step C: Generate measures and alternatives. Traditionally, measures considered in distribution grid planning have been "passive" measures such as grid expansion, reinforcement or reinvestment. This framework in addition considers active measures and differentiates between a) active measures in the grid (i.e. under the control of the grid company) and b) active measures with end-users (i.e. based on demand- or supply-side flexible resources). In contrast to "passive" measures, active measures modify load and generation and thus power flow during grid operation.

Step D: Techno-economic analysis of alternatives and assessment of risk. The type of analysis used to assess whether grid planning alternatives are technically acceptable will depend on the problem, and can include power flow analysis, power quality analysis, short-circuit analysis, reliability analysis, and transient and stability analysis. In contrast to traditional grid planning frameworks, these analyses should be seen as a part of a risk analysis that considers the probability of outcomes (e.g. voltage limit violation) as well as the severity. This can be done e.g. using scenario analysis, Monte Carlo sampling, probabilistic power flow methods or fuzzy numbers. Norwegian grid companies are furthermore required by law to develop the distribution grid in a socio-economic rational manner [9] and should thus carry out a socio-economic analysis of the grid planning alternatives. Socio-economic costs in general include investment costs, operation and maintenance costs, costs of energy losses, interruption costs, and congestion costs [3].

Step E: Multi-criterion evaluation of alternatives. In addition to the socio-economic criterion, the measures are also evaluated according to other criteria as defined in step A. These may include public opinion, negative esthetical and environmental impacts of measures, positive environmental impacts such as increased VRE integration, and impacts on security of supply. Non-monetized impacts of grid planning measures can be considered together with the economic impacts in a multi-criterion decision analysis framework.

Step F: Discard or modify alternatives. The framework is designed to encourage an iterative planning process where the considered measures can be modified and improved by incorporating the insights gained through previous iterations of the process. Different measures can be combined in the grid planning alternatives, and active measures can be considered as temporary measures to defer grid reinforcement. This makes the plan more flexible in the sense that it gives the grid company the ability to update and modify the subsequent steps of the plan based on updated information.

Step G: Overall assessment and ranking of alternatives. The final step involves trading off the assessments from the previous steps according to the preferences of the decision maker. Economic and other criteria are taken into account in constructing a ranked list of all the grid planning alternatives. The assumptions underlying the assessment should be communicated to the decision maker and relevant uncertainties should be quantified and visualized. This approach can be contrasted with many of the optimization models proposed in the research literature that often returns only a single solution and does not provide the decision maker with insight into why this particular solution was selection or how sensitive the selection is to uncertainties [2].

III. Case Study Demonstration

To describe and demonstrate the proposed framework in more detail, we consider a case with a hypothetical Norwegian distribution grid company. The need considered in this case is related to voltage problems in a distribution grid with a growing amount of distributed solar photovoltaic (PV) generation. The case is based on [6], and the distribution system data are described in detail there and in references within. In this paper, we focus on the low-voltage (LV) part of the grid beneath a 22 kV / 230 V distribution transformer, as shown in Fig. 2a. The case assumes that rooftop PV with three-phase inverters is installed with several of the end-users in the LV grid. Over the next years, several new installations are expected that may cause overvoltage in periods of high PV power output, but there is uncertainty associated with the future development in PV penetration.

This case is deliberately chosen to be relatively simple to illustrate the application of the framework in a transparent manner. Although the planning problem has a limited scope and involves relatively small grid costs, it nevertheless serves to demonstrate key points for all the steps of the framework, as described in the following subsections. The planning problem is also sufficiently complex to justify the application of probabilistic methodology. In this paper, we focus on modelling of variability and uncertainty in PV generation. Voltage problems in the future due to distributed PV is a concern among Norwegian grid companies even though the PV penetration in Norway currently is relatively low [11].

A. Establishing grid planning scope and premises

The need and scope for the considered grid planning problem is as outlined above. Norwegian laws and regulation obligate grid companies to provide grid connection to “prosumers” such as those considered in this case. At the same time, grid companies are obligated to ensure that the supply voltage satisfy certain power quality criteria [11]. This is the main objective for this grid planning problem. Here we will focus on long-duration overvoltage and the requirement that the voltage magnitude should be within ±0.1 p.u. Voltage limit violations represent a risk to the grid companies. In this case, the grid company considers a policy of accepting a limited risk of overvoltage, as they may not be willing to eliminate this risk at any cost.

It is also part of this grid company's policy to promote electricity generation from VRE sources and support prosumers when possible. The company therefore has an interest in BESS. The motivation is both to enable increased VRE penetration and to gain experience with the use of BESS as a potential active distribution grid measure. Several Norwegian grid companies have BESS demonstration projects. In the future, regulation may prohibit them from investing in BESS to own and operate themselves, but they may incentivize the prosumer community to invest in a BESS or procure BESS services from a third party. In all cases they should consider a wider, societal perspective when assessing whether BESS may be a cost-effective alternative. The socio-economic analysis horizon in this case is chosen to be $y_{\text{end}} = 10$ years, and we assume a (real) discount rate f_d of 4.5%.

B. Modelling of load demand and generation

For this case study we focus on distributed PV generation variability and uncertainty. Preceding work [6] considered operational planning and proposed probabilistic PV generation models for that purpose, applied to a typical day in July. For long-term planning purposes one needs to capture time dependence, chronology and variability representative for the location over a full year. Available yearly time-series with hourly resolution are described in [6]. To reduce computation time, a selection of days covering five months are sampled to represent the full year. Probability weights assigned to the days correspond to the fraction of the full year that they represent. Load demand is modelled similarly, capturing also the time-dependent correlations with solar irradiance. Sample density is higher for summer months since these are most important to represent accurately to estimate the risk of overvoltage.

To also capture the uncertainty in the long-term development in PV penetration over the analysis horizon, the grid company constructs three scenarios based on available knowledge [4]. These scenarios are shown in Fig. 2b and are predictions of the total area of installed PV panels within the LV grid. The basis scenario is assumed to be most likely and is assigned a (subjective) probability $p_{k=2} = 0.5$ of being realized, while the low and high scenarios are assigned probabilities $p_{k=1} = p_{k=3} = 0.25$.

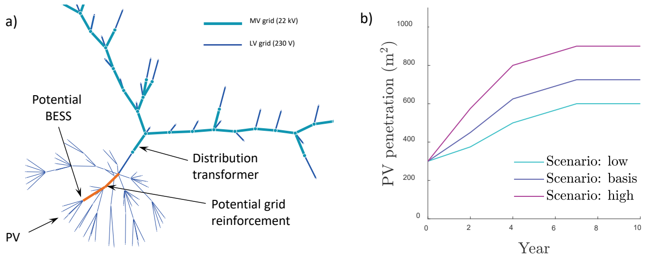

Fig. 2. a) Schematic of the distribution system, based on [6]; b) long-term prognosis for distributed PV penetration.

C. Generate measures and alternatives

Keeping the existing grid without taking any measures (denoted #0, i.e. the zero alternative) is not believed to be an acceptable alternative in the long term. This is verified in the risk assessment described in Sec. III.D. The alternatives that are initially considered by the grid company are summarized in Table 1. More complex alternatives comprising several measures are considered in the next iteration of the planning process in Sec. III.F. For all the measures, the lead time for implementing the measure is well below one year.

TABLE I. ALTERNATIVE MEASURES.

Alternative	Type	Investment cost	Economic lifetime
#1) Grid reinforcement	Passive	130 kNOK	30 years
#2) Community BESS	Active (in the grid)	600 kNOK	10 years
#3) PV curtailment	Active (with end-users)	n/a	n/a

The traditional, “passive” measure (alternative #1) in this case is to reinforce the grid by installing a parallel set of LV underground cables (TFXP 4x240 Al, shown in Fig. 2a as an orange line) along the radial. The new and existing cables connect the distribution transformer to a bus that is located centrally in the prosumer community and to which existing and prospective PV installation owners are connected. The remaining economic lifetime of the existing cables exceeds 10 years and thus would not have to be replaced during the analysis horizon. Technical data and cost data from [3] are assumed and consumer price index adjusted to cost level 2019.

A stationary grid-connected community-level BESS is considered as a measure (alternative #2) to allow higher amounts of distributed PV generation to be integrated in the distribution system without violating voltage limits. The most suitable location has been determined to be the central bus in the prosumer community. Optimal siting of the BESS is therefore not part of the scope of this simplified planning problem. The solution that is initially considered consists of six Tesla Powerwall 2 BESSs [12]. Degradation is accounted for in a simplified manner by limiting the depth of discharge and using only the usable energy capacity specified with the 10-year warranty.

To estimate the potential operational benefits of this active measure, we employ the MPOPF model presented in detail in [6]. This model emulates the charging/discharging and reactive power control schedule of the BESS under the assumption that it operates to maximise the socio-economic surplus in the distribution system while respecting technical constraints and accounting for the expected future value of stored energy [13]. This socio-economic operational objective is consistent with the socio-economic planning objective of the grid company. In this sense, the BESS could be regarded as an active measure in the grid even if it is not directly controlled by the grid company.

Finally, as an active measure with end-users, active PV curtailment is also considered (alternative #3). It is assumed that the prosumers can implement a control scheme for the PV installations that modifies the active power output of the inverters so that the voltage level is always at or below the limit. Current regulation in Norway does not allow curtailment of DG as a permanent measure without separate agreement and compensation, but a previous study has shown that it can be a socio-economic cost-effective measure for the case of hydropower DG [14].

D. Techno-economic analysis of alternatives and assessment of risk

Since long-duration voltage problems are considered in this case, power flow (PF) calculations is the relevant type of technical analysis. We carry out ordinary sequential PF calculations using [17] to assess the technical risk for alternatives #0 and #1, whereas multi-period OPF and sequential OPF calculations are used for the active grid measures (#2 and #3). To reduce the computation time, only four of the ten years are evaluated explicitly, and results for the remaining years are estimated by linear interpolation.

We first consider the zero alternative (#0) and illustrate the risk of overvoltage in Fig. 3. This figure shows how the number of days (left) and hours (right) with overvoltage problems is expected to develop for the three PV scenarios if no measures are taken. For each scenario, both the expected values and the areas between the 5$^{\text{th}}$ and the 95$^{\text{th}}$ percentile (estimated by bootstrap resampling) are shown. This is clearly not an acceptable alternative in the long term: After four years, one can expect voltage problems on between around 20 and 90 days of the year, depending on which scenario is realized and the solar irradiance conditions that particular year. However, if the low or basis scenario are realized, voltage problems are expected only up to around five days a year for the first two years. This is a risk that the grid company is willing to accept. If the high scenario is realized, on the other hand, measures must be taken before two years. A deterministic counterpart to this technical analysis would be to consider the maximal PV power output under the high scenario and conclude that alternative #0 becomes unacceptable already after year 1. The analyst and the decision maker would in that case be ignorant of what the risk of overvoltage actually is (as visualized in Fig. 3). For the alternatives #1–#3, the risk is reduced to an acceptable level: There will be no hours of overvoltage during the planning horizon for any of the scenarios according to the analysis.

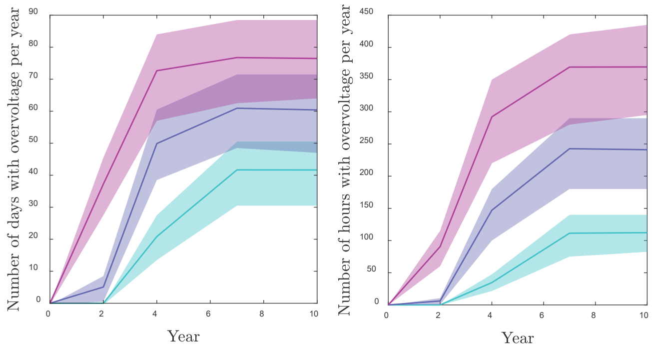

Fig. 3. Risk of overvoltage problems over the planning horizon in case no measures are taken (#0).

The techno-economic analysis involves calculating the present value of the total socio-economic costs incurred over the analysis horizon for each alternative i:

$$\mathrm{PV}_i = \sum_{y=1}^{y_{\mathrm{end}}} \frac{C_{y,i}^{\mathrm{inv}} + C_{y,i}^{\mathrm{op}}}{(1+f_{\mathrm{d}})^y} - \frac{C_i^{\mathrm{res}}}{(1+f_{\mathrm{d}})^{y_{\mathrm{end}}+1}}, \quad (1)$$

where $C_{y,i}^{\mathrm{inv}}$ are investment costs, $C_{y.i}^{\mathrm{res}}$ are residual values calculated assuming linear depreciation. The operational costs C_y^{op} for year y are calculated using

$$C_{y,i}^{\mathrm{op}} = C_{y,i}^{\mathrm{fixed}} + (8760\ \mathrm{h}) \sum_{t=1}^{N_t} p_t c_{y,t} \Big(P_{y,t,i}^{\mathrm{loss,grid}} + P_{y,t,i}^{\mathrm{loss,BESS}} + P_{y,t,i}^{\mathrm{loss,PV}} \Big) \quad (2)$$

Here, the sum goes over a sequence of $N_t = 24 \times N_d$ time steps (hours) t that make up N_d days representing a full year, and p_t is the probability weight assigned to each hour. The three power loss terms $P_{y,t,i}^{\mathrm{loss},\cdot}$ are due to grid losses, BESS charging/discharging inefficiency, and PV curtailment and are calculated from the PF and OPF solutions. The hourly day-ahead electricity price $c_{y,t} = \bar{c}_y c_t$ varies over the year according to a relative profile c_t as in [6], with a yearly average $\bar{c}_y$ according to the long-term electricity price forecast of [16]. $C_{y,i}^{\mathrm{fixed}}$ represents fixed annual operation and maintenance costs, for which we use the assumptions in [17].

For the purpose of illustration, we in this first iteration of the planning process assess alternatives assuming a deterministic and implicitly risk-averse grid planning strategy: Assuming that the grid company does not want to take the risk of a rapid increase in PV penetration (the high scenario), it implements a measure already in year 1 to eliminate this risk. A less risk-averse strategy will be considered in the next iteration of the planning process and described in Sec. III.F.

Fig. 5 compares the socio-economic cost compositions for the alternatives for case that the basis PV penetration scenario is realized. Annual operational costs due to energy losses are illustrated on the left-hand side for the two active measures. One can notice how for this scenario, the socio-economic costs of PV curtailment in alternative #3 increases over the analysis horizon. The present value of the total socio-economic cost of the alternatives is shown on the right-hand side of Fig. 5. It can be seen that in this case, the main difference is due to investment costs, and in particular the BESS alternative (#2) is not cost-effective due to high investment costs. Operational costs in comparison differ only slightly between the measures. These conclusions also hold for the other two scenarios not shown in Fig. 5.

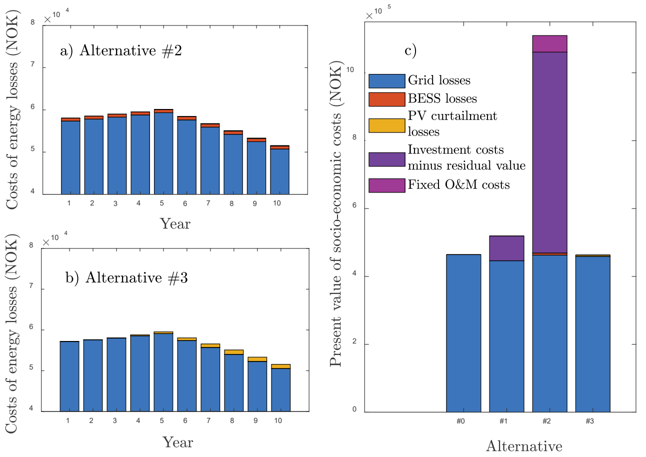

Fig. 4. Socio-economic costs for the basis PV penetration scenario: Annual costs of energy losses for alternative #2 (a) and #3 (b), and present value (c).

E. Multi-criterion evaluation of alternatives

Table II illustrates the performance of the alternatives with respect to a selection of economic and non-economic criteria mentioned in Sec. III.A. The economic criterion is the net present value, $\mathrm{NPV}_i = \mathrm{PV}_{i_{\mathrm{ref}}=1} - \mathrm{PV}_i$, which evaluates each alternative i relative to the reference alternative (#1). The table shows both the expected value calculated using $\overline{\mathrm{PV}}_i = \sum_{k=1}^{3} p_k \, \mathrm{PV}_{i,k}$, where $\mathrm{PV}_{i,k}$ denotes the socio-economic cost if scenario k is realized, and the uncertainty interval due to scenario uncertainty (in parentheses). The amount of VRE lost due to PV curtailment is calculated and presented similarly. Alternative #3 is preferable to the two others according to the socio-economic criterion but is less preferable if more weight is put on the criterion of VRE integration. However, the impact of #3 on VRE integration is relatively uncertain as it depends on the uncertain development in PV penetration. Increased experience in the grid company on the use of active grid measures can be considered as a separate criterion and may be an argument for BESS investment if the grid company can justify the additional socio-economic cost of 590 kNOK.

TABLE II. MULTI-CRITERION EVALUATION OF ALTERNATIVES.

Alternative	NPV	Lost VRE	Experience
#1) Grid reinforcement	0	0	-
#2) Community BESS	- 591 kNOK -(590–593 kNOK)	2.7 MWh (0.2–9.3 MWh)	++
#3) PV curtailment	+ 56 kNOK (50–59 kNOK)	22 MWh (7–45 MWh)	+

F. Discard or modify alternatives

The techno-economic analysis in the first iteration of the planning process (Sec. III.D and III.E) showed how the active grid measures were both unfavourable due to high socio-economic costs and potentially high VRE losses, respectively. In the next iteration we therefore discard alternatives #2 and #3 and consider new, modified alternatives combining grid reinforcement with active and temporary measures. We furthermore adopt a less risk-averse grid planning strategy where the grid company waits with implementing measures until PV penetration uncertainties are (partially) realized. In other words, temporary active measures are used to manage risk associated with long-term uncertainties [20], and the timing of measures will depend on the actual PV development.

A realization of this grid planning strategy is illustrated in Fig. 5. Here, the timing of measures for the low scenario (left) and the basis scenario (right) are compared. We refer to these new alternatives as following a risk-informed strategy. The alternatives are denoted #4 and #5 for BESS and PV curtailment as the temporary measure, respectively. Since the BESS in #2 appeared to be over-dimensioned, half the capacity is chosen for #4, and the BESS is sold when the grid is reinforced. We will in addition compare with a new alternative #6 that follows a similar strategy but only considers passive measures (grid reinforcement). We keep alternative #1 (grid reinforcement in year 1, following a risk-averse strategy) as the reference alternative. The socio-economic costs and benefits of risk-informed strategies can then be compared with the risk-averse strategy from Sec. III.D.

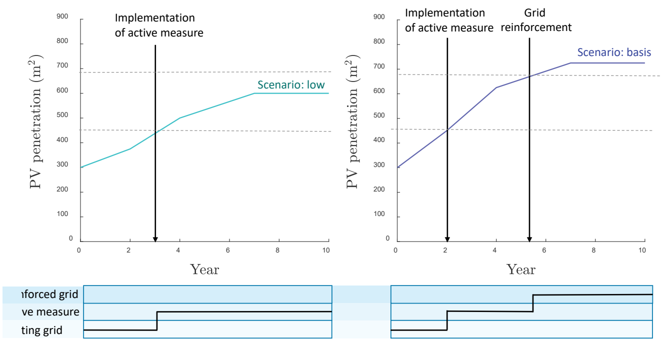

Fig. 5. Grid planning alternatives using active measures (BESS or PV curtailment) as temporary measures to defer grid reinforcement.

G. Overall assessment and ranking

Table III shows the evaluation of the alternatives from the second iteration of the grid planning process according to economic and non-economic criteria. Comparing with the initial alternatives in Table II, alternatives #4 and #6 based on a risk-informed strategy are cost-effective to the corresponding risk-averse alternatives (#2 and #3). Both the expected amount of VRE lost and the uncertainty in the outcome is reduced for the alternatives in Table III.

TABLE III. EVALUATION AND RANKING OF ALTERNATIVES.

Alternative (ranked)	NPV	Lost VRE
#5) PV curtailment as temporary measure	+ 34 kNOK (19–58 kNOK)	3.3 MWh (1.5–6.0 MWh)
#6) Grid reinforcement (risk-informed strategy)	+ 12 kNOK (6–18 kNOK)	0 MWh
#4) BESS as temporary measure	- 120 kNOK (- 95–164 kNOK)	0.67 MWh (0.33–1.07 MWh)
#1) Grid reinforcement (risk-averse strategy)	0.0 kNOK	0 MWh

Future PV penetration was the main uncertainty in this case and is explicitly accounted for in the results in Table III. The BESS investment cost is also uncertain, but we have checked by performing a simple sensitivity analysis that it needs to be reduced by 81% for #4 to be cost-effective. Modelling uncertainties related to the actual operation of the BESS (i.e. its control system), degradation and useful lifetime contribute to increasing the overall risk of #4. After an overall assessment, the alternative ranked highest by the grid company in this example is a strategy based on PV curtailment as a temporary measure (#5), since it gives acceptable voltage quality, is socio-economic effective, and most likely avoids unacceptable VRE losses. However, the grid company may reconsider this ranking if new information becomes available before a measure is to be implemented. In a third iteration of the planning process it could also develop more cost-effective BESS alternatives by considering additional BESS services ("benefit stacking") such as frequency regulation [17].

IV. Discussion and Conclusion

The aim of this paper was to establish a framework and demonstrate it with selected methodology applied to a specific case. Although the BESS alternative was not acceptable for this specific case according to a socio-economic criterion, BESS could be part of cost-effective alternatives e.g. for more remote locations with higher grid reinforcement costs. Moreover, results were presented for a small part of an LV grid, and generalizing the analysis to e.g. multiple comparable LV grids would increase the value of a judicious choice of grid planning strategy. It should be stressed, however, that the methodology is general, and the case study served to demonstrate some of the key aspects of the framework: the characterization of the planning problem, including the needs and relevant uncertainties; how costs and benefits of both passive and active measures can be assessed; the application of a socio-economic planning criterion while also considering relevant non-monetary criteria; and a pragmatic, iterative approach to develop and assess grid planning alternatives.

The case study demonstrated the value of a probabilistic approach to distribution grid planning: The analysis accounted for PV generation variability and uncertainty and showed how short-term variability can be managed using active measures and how long-term uncertainties can be managed by using them as temporary measures. The requirement for input data is in general a challenge for probabilistic methodologies, and, focusing on PV variability, the case study demonstrated the value of adequate data. Other types of DG or loads driving the need for grid planning can also be considered in the framework, and for each, appropriate data are required for the probabilistic analysis. The problems and needs will also determine the selection of methodology to incorporate in the framework: undervoltage or overloading problems may require models for flexible loads as an active measure; power quality problems over shorter (sub-hourly) time scales requires models and data with higher time resolution; reliability of supply challenges driven by aging grid assets requires models for the probability of failure.

There are several practical as well as methodological challenges that must be considered when applying probabilistic approaches to grid planning decision processes. Major uncertainties are for instance related to future regulatory conditions and city and municipal development. Such uncertainties are not easily modelled using probabilistic models, nor are they easily managed by grid companies. Probabilistic approaches can be perceived as more complex, less transparent, and more difficult to understand; grid companies have limited experience with their use and may be reluctant to change from their current practice [19]. If decision makers are presented with information about the risk for different alternatives, they need to have the necessary training to interpret the information and account for it in the decision process. Risk information is also most useful if the decision makers have an explicit risk policy and are conscious of the risk preferences with which to judge the information.

Despite practical challenges, there are clear advantages to a probabilistic approach. In a purely deterministic approach, relevant uncertainties are not accounted for at all, and the decision maker would be ignorant of the risks involved in the planning problem. Making information about uncertainty and risk explicit to decision makers thus contributes to moving from risk-ignorant to more risk-informed decision processes. Which methods are best suited to visualize and communicate uncertainties and risk is still an outstanding research question, and risk information will in practice only form part of the decision support. However, the demonstration of the proposed grid planning framework has illustrated how probabilistic analyses can contribute to more comprehensive assessments of planning alternatives and better grid planning decisions.

Acknowledgment

This work has been funded by CINELDI – Centre for intelligent electricity distribution, an 8-year Research Centre under the FME scheme (Centre for Environment-friendly Energy Research, 257626/E20) of the Norwegian Research Council. The authors gratefully acknowledge the financial support from the Research Council of Norway and the CINELDI partners and thank Ove Wolfgang, Kjersti Berg, Tonje Skoglund Hermansen and Hanne Vefsnmo for input to and discussion of parts of this work.

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