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Methodology for Evaluating Grid Development Strategies Considering Real Options and Risks

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***Abstract*— Traditional power grid planning is based on passive measures such as reinforcing the grid and using present value to compare different grid development plans. However, this approach does not accurately describe the real options value of using active measures, such as energy storage or demand-side load shifting, for postponing grid reinforcement through a "wait-and-see" approach to handle uncertainty in long-term load growth. However, the value of using active measures may come at the price of reducing the security margins in grid operation. This leads to an increased risk of problems during grid operation, and this risk must be weighed against the value of using active measures. This paper presents a methodology for quantifying both the value and risk (or price) of real options related to grid development strategies using active measures, providing grid planners with more comprehensive information about the advantages and disadvantages. The methodology is demonstrated using an illustrative and simple case for a medium voltage reference distribution system, where flexibility from local energy communities is considered as an example of an active measure. The case study illustrates how some risk-taking is required to realize the value from using active measures.**

***Index Terms*—power system planning, flexibility, real options, scenario**

I. Introduction

As a growing number of countries have vowed to achieve net zero emissions by 2050, the path forward requires an electrification of the energy demand, such as in transport and industry. This leads to a significant growth in power demand, but it is uncertain when and where new loads will appear. This poses a great challenge to the power grid planner, having to make large grid investment decisions with limited information on future developments.

Power grid planners now also have a larger selection of measures to choose from in their grid planning activities; both traditional (passive) measures, by reinforcing the grid, or active measures. Active measures can include energy storage, demand response from local energy communities (LECs) or reactive power from fast-charging stations (FCS). Relying on these active measures in grid planning is often referred to as *active grid planning*. Step-by-step active distribution grid planning frameworks have been developed in [1], [2]. The active grid planning process has also been formulated as mixed-integer linear programming problems, where the optimization results in multi-stage plans [3]–[8]. Our previous work [9] applied a similar approach, performing an economic assessment of active measures such as LECs and FCSs as well as passive measures. It was demonstrated on a reference distribution system [10] where undervoltage rather than line overloading was the operational challenge (or grid problem) triggering the need for grid planning. The methodology in [9] therefore focused on undervoltage problems, and this is the case also in the present paper.

Traditionally, evaluating investments has been done comparing present value (PV) calculations [1], [2], [11]–[15], minimizing PV of the total costs. However, PV methods are not able to evaluate the strategic dimension of the investments and do not permit appropriate risk and uncertainty management [16]. Also, these PV-based methods typically assume that the resulting grid development plans are "fixed", while in reality they may be dynamic and updated during the planning horizon as new information becomes available and uncertainties are resolved. An alternative economic assessment method is real options valuation (ROV). Real options can be seen as the ability to postpone and modify investment

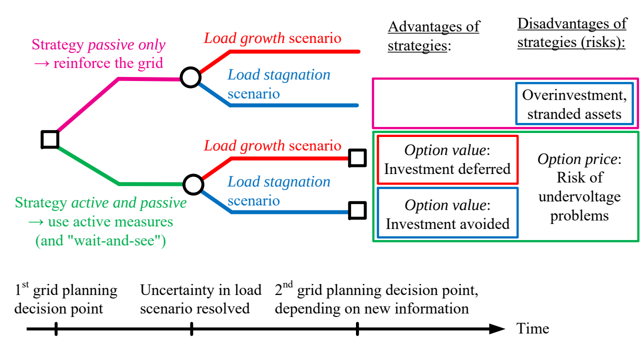

Fig. 1. Decision tree for strategy choices under load growth uncertainty of a) reinforcing the grid or b) deferring the investment decision and using active measures (e.g., demand-side flexibility) as a (potentially temporary) measure.

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TABLE I
THE CONTRIBUTION OF THIS WORK, COMPARED TO RELATED WORKS IN RECENT LITERATURE. THE PAPERS HAVE BEEN COMPARED ACCORDING TO THE FOLLOWING TOPICS: I) VOLTAGE-ORIENTED (VO) APPROACH, II) MULTI-STAGE PLANNING, III) ACTIVE MEASURES CONSIDERED, IV) NET PRESENT VALUE (NPV) CONSIDERED, V) REAL OPTIONS VALUATION (ROV) AND IV) RISK QUANTIFICATION (RQ) OF STRATEGIES

Reference	VO	Multistage	Active	NPV	ROV	RQ
[3]	–	✓	✓	–	✓	–
[4]	–	✓	✓	✓	✓	✓
[5]	–	✓	✓	–	✓	–
[6]	–	✓	✓	–	–	–
[9]	✓	✓	✓	✓	–	–
This work	✓	✓	✓	✓	✓	✓

decisions to mitigate risk of overinvestment, which could lead to stranded assets. Real options thinking enables the grid planner to decide whether, how, and when to implement active measures to postpone grid investments. Planners can take use of these alternatives to prevent overinvestment losses by tailoring their future actions to changing future conditions [17].

The problem addressed in this paper is conceptually illustrated in Fig. 1. It shows a decision tree from the perspective of a distribution grid planner that is faced with expected but uncertain increase in load demand in a grid area. At the first decision point, the system loading is such that measures must be implemented to avoid operational challenges and unacceptable security of supply. The traditional grid development strategy entails reinforcing the grid (using only passive measures) to meet the expected load growth. An alternative strategy is to use active measures to "buy some time" and wait for more information about the actual increase in load demand before making the investment decision at a later point. To make an informed decision at the first decision point, it is relevant for the grid planner to estimate both the option value and option price associated with a strategy based on active measures. The option price here means the risk of operational challenges by postponing grid reinforcements.

Multistage grid planning optimization models typically suggest a single optimal grid development plan but does not inform the decision maker (the grid planner) about the risks associated with different grid development plans or the value of being able to adapt the grid development plan to new information. Relevant work in the existing research literature is summarized in Table I. With this motivation in mind, this paper is intended to make the following contributions:

- It presents a methodology for quantifying and accounting for both the value and price (risk) of real options in the development of active distribution grids. More specifically, it includes:
- A simulation-based risk assessment method for estimating undervoltage risks associated with grid development strategies.
- Real options valuation of active measures, complementing the traditional present value method to account for the uncertainty in the load scenario.

The paper is organised as follows: The methodology is presented in Section II, where subsections II-A and II-B describe the quantification of the i) risk and ii) value, respectively, of real options associated with active measures. Here, flexibility provision from LECs is used as an example of active measures, building upon the grid planning methodology previously presented in [9]. Other relevant measures for voltage support, such as using static/dynamic compensation systems or transformer taps, are not considered in this work. To demonstrate the methodology, a case study with an illustrative example is presented in Section III. This section also illustrates how estimates of the option value and option price together provide grid planners with a more comprehensive evaluation of grid development strategies than traditional approaches. Finally, the paper is concluded in Section IV with some remarks on generalization and extensions of the methodology proposed for future work.

II. METHODOLOGY

To give an overview of the methodology proposed in this paper, Fig. 2 illustrates a general process for planning of active distribution grids according to the framework presented in [2]. This framework was implemented and demonstrated in [9] by integrating operational models for FCSs and LECs as active measures. That work focused on methodology for economic assessment and left methodology for handling uncertainties and risks for future work. The present work extends [9] with i) methodology for assessing the risks (option price, or disadvantages) due to load demand uncertainties and ii) the option value (advantages) of using active measures to manage these uncertainties. The right-hand part of Fig. 2 shows the modules integrated into the framework in this paper. The modules that are new compared with the framework implementation presented in [9] are shown in yellow.

The following subsections will describe the methodology of the extensions (i) and (ii) mentioned above, while the overall assessment of the grid development strategies is demonstrated as part of the case study in Sec. III-D. For the sake of space, the reader is referred to [9] for details on the other parts of the methodology indicated in Fig. 2. Briefly put, in [9] an operational model for selected representative days is combined with a grid investment optimization model. For a given long-term load scenario, with an expected load demand in the system that one has accommodate at the end of a multi-year planning horizon, the investment model outputs a target grid. This target grid guarantees acceptable voltage values, given the load assumptions in the input data to the investment model. The methodology in [9] also suggests a grid development plan that describes the transition from the existing grid to the target grid. However, it should be emphasized that the methodology for evaluating grid development strategies proposed in the present paper is not restricted to grid development plans that are outputs from the methodology in [9]; it is generally applicable to any grid development plan, either suggested by an optimization model or manually generated through traditional approaches to grid planning.

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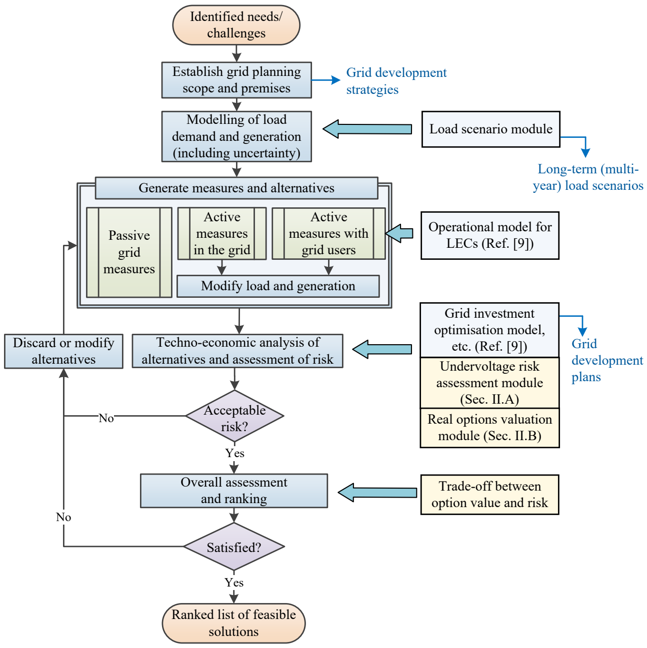

Fig. 2. Framework for planning of active distribution grids, adapted from [2]. The modules of the framework implementation considered in this paper are shown to the right. The parts of the methodology that are new compared with the framework implementation presented in [9] are shown in yellow.

A. Undervoltage risk assessment

A grid development strategy will determine the grid development plan for a given load scenario. The risk assessment module assesses the risk of undervoltage (long-duration rms variations) in the grid if a given grid development plan is implemented and a given load scenario is realized. The risks considered are due to two types of uncertainty in the load demand: 1) The long-term uncertainty in how the total peak load in the grid area evolves over the planning horizon (i.e., the load scenario), and 2) the shorter-term uncertainty in the load time series for the representative days considered. In [9], 1) a single load scenario and 2) a single representative day was used to demonstrate the economic assessment methodology of integrating LECs in grid planning. The risk assessment module will assess how robust the grid development plan is with respect to different realizations of these uncertainties. The steps of the simulation are as follows:

1) For a given grid development plan and a given load scenario, start with the first year of the planning horizon.
2) Run power flow calculations for all hours of the year. (For this paper, a forward/backward sweep power flow implementation for radial distribution grids was employed.)
3) Identify the days and hours with undervoltage and the severity of each undervoltage event.
4) If there are days with undervoltage events:
   a) Run a 24-hour operational flexibility cost minimisation model from LECs given in [9] (Section III B). ***Input:*** *Reference load profiles for LECs without flexibility activation,* ***Output:*** *Adjusted load profiles and operational costs due to flexibility activation*
   b) Update the load profiles of LECs with the profiles obtained from operational model.
   c) Re-run the power flow for the same day.
   d) Record the number of hours with undervoltage and the severity of each undervoltage event.
   e) Repeat step a) to d) for other days.
5) If there are no more days with undervoltage events for the year, repeat steps (2) to (4) for the next year.
6) When the simulation reaches the end of the planning horizon, repeat steps (1) to (5) for the next combination of grid development plan and load scenario.

Based on the recorded undervoltage events, different risk indicators can be calculated, for instance based on [18], and given as output for each year of the planning horizon. In this paper, results are presented for the expected number of undervoltage hours per year, as a measure of the likelihood dimension of the risk of undervoltage.

B. Real options valuation

The value of the real option is calculated as the net economic benefit of using active measures to postpone grid investment decisions [5]. In other words, it is the difference in the expected value of the total PV of investment and operational costs when comparing two types of strategies: i) planning for only passive measures and reinforcing the grid already at decision point 1, and ii) deferring the grid investment decision by using active measures. In brief this is referred to as the *value of active measures* and calculated as:

$$\begin{aligned}\mathrm{ROV} &= \underset{\Omega_{\mathrm{scen}}}{\mathbb{E}}(\mathrm{PV}_{\mathrm{reinf}}) - \underset{\Omega_{\mathrm{scen}}}{\mathbb{E}}(\mathrm{PV}_{\mathrm{active}}) = \\ &\sum_{k\in\Omega_{\mathrm{scen}}} p_k\,\mathrm{PV}_{\mathrm{reinf},k} - \sum_{k\in\Omega_{\mathrm{scen}}} p_k\,\mathrm{PV}_{\mathrm{active},k}\end{aligned} \tag{1}$$

In the module, the expression above is implemented as a loop over grid development strategies (allowing the use of active measures or not) and over load scenarios $k \in \Omega_{\mathrm{scen}}$ associated with probabilities p_k:

1) A grid development plan is specified depending on the grid development strategy and which load scenario is realized.
2) Each set of scenario and grid development plan has operational costs, obtained from the operational model, plus investment costs.
3) The PV of each set of grid development plan and scenario are calculated from investment and operational costs
4) The option value is calculated from Eq. 1.

III. Case Study: Illustrative Example for a Medium Voltage Distribution System

This section illustrates the methodology through a case study using a medium voltage (MV) reference distribution system [10]. The case builds upon the case used in [9], which presented results for deterministic grid development plans generated on the basis of a single scenario for the load growth in the system over a 10-year planning horizon. The results

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that the present paper builds upon are briefly summarized in Section III-A. Section III-B uses ROV results to illustrate how the value of active measures increases when considering the uncertainty in the load scenarios. Section III-C considers the uncertainty in operating conditions during the year and quantifies the risk of voltage problems for different grid development plans and load scenarios. Section III-D combines the results from Sections III-B and III-C and illustrates how the methodology can be used by grid planners to evaluate the grid development strategies by weighing the value of active measures against the risk of undervoltage problems.

A. Deterministic grid development plans considering LECs

The case study building upon [9] considers a radial MV (22 kV) distribution system based on a real, Norwegian distribution grid [10]. The data set also includes individual load demand time series for a year with hourly resolution for each distribution substation in the grid model. For the sake of brevity, the reader is referred to the data article [10] as well as to [9] for further details about the case.

In the reference year (2021) the system is moderately loaded and there are no grid problems. However, over the next few years, new residential areas (neighbourhoods) will be connected to the grid so that parts of the system by 2025 is expected to experience undervoltage problems during parts of the year, with voltage values beneath the planning limit set to 0.95 p.u. There are also plans for additional residential areas towards the end of the decade that would increase the loading in the system further. The red curve in Fig. 3 shows how the total peak load in the system is expected to increase according to this load scenario. This is what the grid company considers the most likely load scenario, with a probability $p_1 = p = 0.9$, and this is the scenario that was considered in [9]. However, it is also possible that the later residential areas are not realized, which corresponds to the blue curve in Fig. 3 and is associated with the probability $p_2 = 1 - p = 0.1$.

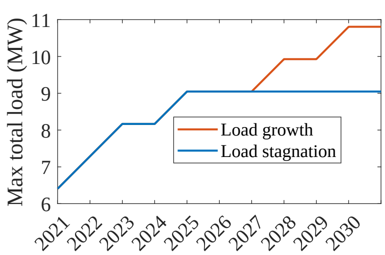

Fig. 3. Load scenarios for new neighbourhoods (potential local energy communities) added to the reference system.

This paper considers the decision about which grid development strategy the grid company should choose as they approach 2025 and measures must be taken to maintain acceptable voltage values. One strategy considered in [9] was to enable the potential flexibility of the new neighbourhoods and use this flexibility during operation as an active measure to avoid voltage problems. Fig. 4 shows the grid development plan resulting from this strategy if the expected *load growth* scenario is realized. The figure shows how by 2028 the active measure alone is not sufficient to maintain acceptable voltage values and some grid reinforcements need to be made. As a benchmark strategy against which to measure the value of active measures, this paper considers a simple, traditional grid reinforcement approach that results in the grid development plan shown in Fig. 5. Here, as soon as measures need to be taken, grid reinforcements are implemented to eliminate the risk of voltage problems during the planning horizon. This can be seen as a risk-averse strategy with the objective to have a grid development plan that is robust to any expected load increases.

	Year									
System solution	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reinforced lines 5-7, 9-12										
Reinforced line 9-12										
Existing grid with active measure (LEC)										
Existing grid										
Accumulated investment costs (kNOK)	-	-	-	-	-	-	-	535	535	846

Fig. 4. Grid development plan following a strategy of using active measures and deferring grid investments (strategy *active and passive*) if the *load growth* scenario is realized. This grid development plan results from the methodology implemented in [9].

	Year									
System solution	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Reinforced lines 5-7, 7-9, 9-12										
Reinforced lines 5-7, 7-9										
Reinforced line 7-9										
Existing grid										
Accumulated investment costs (kNOK)	-	-	-	-	*1 144*	*1 144*	*1 144*	*1 144*	*1 144*	*1 144*

Fig. 5. Grid development plan following a strategy of using only passive measures (strategy *passive only*) and planning for accommodating the *load growth* scenario. This is chosen as the benchmark for the case study.

B. Option value of using LEC as active measure

In the illustrative example considered here, with two load scenarios and up to two decision points, the ROV calculation simplifies to

$$\mathrm{ROV} = \mathrm{PV}_{\mathrm{now}} - [p\,\mathrm{PV}_{\mathrm{deferred}} + (1-p)\mathrm{PV}_{\mathrm{avoided}}] \quad (2)$$

The economic assessment and parameter values from [9] were used to find the present value, where the operational model outputs the total costs of using flexibility in the planning horizon. Equation 2 is in Fig. 6 plotted against the uncertainty in the load scenario. Since two possible load scenarios are considered, the standard deviation of the binomial distribution, $\sqrt{p(1-p)}$, is used as a measure of the uncertainty. Using a traditional PV approach to valuating active measures here corresponds to assuming zero uncertainty and $p = 1$. From the figure, it is clearly shown how the option value of deferring investment using flexibility from LECs increases as the value of p decreases and the uncertainty in load growth increases.

C. Risk of undervoltage

The undervoltage risk assessment module was run for the combinations of grid development strategies and load scenarios presented in Sec. III-A, and the main results are summarized in Fig. 7. As expected, the *passive only* (risk-averse)

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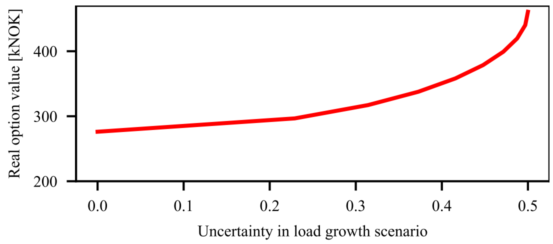

Fig. 6. Real option value (ROV) of using local energy communities as an active measure as a function of the uncertainty in the load scenario. The baseline value of $p = 0.9$ gives an uncertainty $\sqrt{0.9(1-0.9)} = 0.3$.

strategy given by the grid development plan in Fig. 5 almost eliminates the risk of undervoltage over the planning horizon. These results are therefore not included in Fig. 7, but instead, some additional cases are included for comparison: The blue plot in Fig. 7 shows how the risk of undervoltage develops over the planning horizon for a "trivial" grid development plan where no measures are implemented if the *load growth* scenario is realized. If nothing is done, this will result in a annual number of undervoltage hours reaching 80 by year 2030, with an average of 15 undervoltage hours per year over the course of the 10-year horizon. The red curve shows the results for a case where active measures are implemented in year 2025 but without passive measures (grid reinforcement). This is another form of a "risk-seeking" grid development strategy, where the grid planner takes a chance by continuing to operate the system with active measures only. The average annual number of hours with under voltages is reduced to 10.7 with this strategy.

These two reference curves for the undervoltage risk can be compared to the yellow curve for the grid development plan defined in Fig. 4. This curve indicates a strategy that implements both passive and active measures. Until year 2027, the system is solely operated with active measures. The risk of undervoltages is the same in this case as in the reference cases discussed previously (red and yellow curves). The number of hours with voltage problems decreases to zero in year 2028, as illustrated in Fig. 7. This is due to the grid being reinforced from 2027 to 2028, in addition to the availability of active measures. The dashed purple curve shows how the risk will develop for the same *active and passive* strategy if the *load stagnation* scenario is realized. In that case, the grid is not reinforced in year 2028, and the average annual number of hours with voltage problems increases to 2.4. Comparing the purple and the red curves, the figure also shows that provided the load stagnates, the risk of undervoltages is kept at a relatively low level through the adoption of active measures.

The results for the strategy where both active and passive measures are planned for and implemented is represented by the identical yellow plot shown in Figs. 7 and 8. Nonetheless, undervoltages will occur more frequently if the active measures are not available as they were planned for. The black curve in Fig. 8 depicts the case of active measures being planned for from year 2024, but turn out not to be available. In addition, for years 2027 through 2030 the black

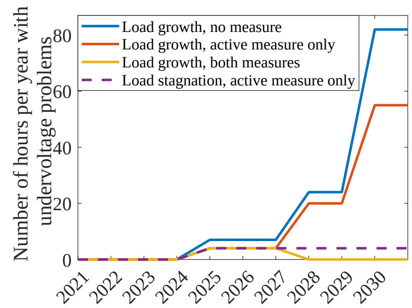

Fig. 7. Visualization of the risk of under-voltage problems depending upon load scenario (solid or dashed lines) and grid development strategy.

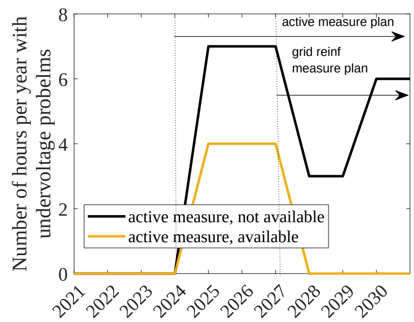

Fig. 8. Visualization of the risk of under-voltage problems depending upon active measure availability.

curve illustrates how the undervoltage risk develops as the grid is stepwise reinforced, i.e., investments at the start of years 2028 and 2030. If the investment requirements are planned with active measures in consideration, and if load growth continues, there may still be voltage problems despite the grid investments if the active measures turn out to be unavailable. This is clear from the fact that the number of undervoltage hours doubles from year 2029 to year 2030.

D. Trade-off between value and risk

A summary of the techno-economic evaluation of combinations of grid development strategies and load scenarios is shown in Table II. In the table, *passive only* refers to the most risk-averse grid development strategy, where the grid reinforcement is made at once. The present value in this case is the highest, and the risk of undervoltage (in average hours per year) is zero, according to the operational model. The *active only* strategy means the grid company procures flexibility services from the LECs, but makes no grid investment. The present value cost of this strategy is much lower than the *passive only* strategy, however, there is a real risk of undervoltage hours that must be weighed against the option value of using active measures. The *active and passive* strategy uses active measures to postpone the grid investment. The table illustrates how the grid planner can investigate the implications of being more risk-averse or risk-seeking by adjusting the initial grid development plans. The values in Fig. 9 are obtained by weighting results for the load growth scenario by a probability 0.9, and conversely, 0.1 for load stagnation. It illustrates that some risk-taking is required to realize the value from using active measures. The results can be used to evaluate if a strategy gives an acceptable risk, depending on the risk profile of the grid company [2].

TABLE II
EVALUATION OF GRID DEVELOPMENT STRATEGIES PAIRED WITH LOAD SCENARIOS. THE PRESENT VALUE (PV) OF THE PLANS ARE SHOWN ALONG WITH THE RISK OF UNDERVOLTAGE IN AVERAGE HOURS PER YEAR OVER THE PLANNING HORIZON.

Load scenario	Strategy	PV (kNOK)	Risk (h/year)
Load growth	Passive only	664.4	0.0
Load growth	Active only	31.8	10.7
Load growth	Active and passive	376.7	1.2
Load stagnation	Passive only	664.4	0.0
Load stagnation	Active only	19.2	2.4

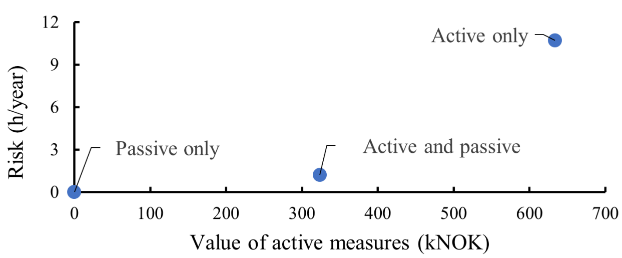

Fig. 9. Evaluation of real options value (on the x axis) and undervoltage risk (on the y axis) for three grid development strategies for $p = 0.9$. Choosing a strategy with a high value of active measures correlates with a higher risk profile.

IV. CONCLUSIONS AND FURTHER WORK

This paper has presented a methodology for quantifying both the real option value and the undervoltage risk associated with using active measures to postpone grid investment decisions. A case study illustrated how a higher option value comes at the price of an increased risk of voltage problems, and how the methodology can be used to consider which grid development strategy gives the best trade-off between value and risk.

The risk assessment method and the case study in this paper only considered undervoltage problems. Other operational challenges would be relevant for other cases, such as overvoltage problems due to distributed generation, overloading problems, or insufficient reserves in case of outages. Such grid problems were left out of scope for this paper, but the principles of the methodology can be generalized to other operational challenges.

To emphasize pedagogical clarity and illustrate the benefits of real options thinking, the case study was purposely kept very simple: Two load scenarios and two decision points. The case study served to illustrate how the value of active measures and the benefits of real options thinking increases as the uncertainty in load growth increases. The benefits of the methodology will moreover increase for cases with significant lead time between the investment decision and implementation of grid reinforcement measure: In such cases, the real option value of postponing investment decisions come at a higher price in terms of the risk during the lead time. This advantage could not be demonstrated in the MV distribution grid case considered in this paper (where lead times are typically less than one year) but will be explored in future work considering a regional (sub-transmission) distribution grid.

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