INCREASE

INCREASING THE PENETRATION OF RENEWABLE ENERGY SOURCES IN THE DISTRIBUTION GRID BY DEVELOPING CONTROL STRATEGIES AND USING ANCILLARY SERVICES

D2.3 Evaluation of potential of the Combined Exploitation of Selected Optimization Techniques

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Table of Contents

List of Figures

List of Tables

List of Abbreviations

ANM	Active Network Management
BC	Business Case
DE	Demand Elasticity
DER	Distributed Energy Resources
DLR	Dynamic Line Rating
DR	Demand Response
DRES	Distributed Renewable Energy Sources
DSM	Demand Side Management
DSO	Distribution System Operator
GSC	Cost for Green Certificate
MAS	Multi-Agent System
ME	Market Equilibrium
RES	Renewable Energy Sources
WT	Wind Turbine
DG	Decentral Generation

1 Introduction

The INCREASE project aims to increase the penetration of distributed renewable energy sources (DRES) in the distribution grid and enable DRES and consumers to participate in the market and provide ancillary services.

When Distribution System Operators (DSOs) want to add large renewable energy sources, like wind turbines, to an existing part of their grids, they are confronted with the question how to mitigate the risk for network congestion as cost-efficiently as possible. Traditionally, DSOs anticipate the risk with network reinforcements, which require considerable investments. Therefore, several alternative solutions, so-called Active Network Management (ANM) techniques, are being studied, in order to reduce, defer or avoid the network investments by the DSO.

In D2.2 we presented two technologies that can be used to achieve this goal, i.e., Demand Side Management (DSM) and Dynamic Line Rating (DLR). In this deliverable we compare these solutions from a planning perspective for Medium Voltage (MV) grids and compare them with alternatives like grid investments and curtailment. We derive a number of rules of thumb for DSOs when facing requests for attaching DRES to their existing grids, for different regulatory frameworks.

The second part of this deliverable presents a coordinated OLTC control approach for MV grids based on a state estimator. The result of the state estimator is the current state of the grid, including the estimated real-time power flow of each MV PoC. Using this information, a nonlinear integer program can be formed to optimize the tap positions of the main transformer and regulating transformers. Compared to the traditional method, the proposed method can consider the distribution of the MV loads and realize the coordination of the main transformer and regulating transformers.

2 Business Case Comparison for different ANM techniques

2.1 Connecting DRES to existing MV grids

When a DSO gets a request for connecting DRES to an existing part of the grid, a study will be performed to assess if this DRES can inject its peak load power at any time (in normal net conditions). The classic calculation rules and limits are used. If this condition is not met, the DSO will perform the necessary network reinforcements, e.g., replacing feeder cables with thicker cables, upgrading transformers, etc.

To allow more DRES in existing grids at a reasonable cost and reduce time to connect these energy sources to the grid, other solutions are currently investigated:

Curtailment

In case that only in rare situations the DRES cannot inject all its produced energy into the grid, it might be more cost effective to temporarily curtail the production and possibly compensate the DRES owner, instead of performing expensive and time consuming investments to only allow a small fraction of extra renewable energy in the grid. As such the DRES owner will be able to connect faster to the grid.

If a fine grained control of the DRES is possible, in cases of abnormal net conditions (e.g. an N-1 situation on transformer level), it might be possible to even allow more injection. Traditionally the DRES would be typically shut down completely while with such a real-time, fine-grained control some injection could still be possible.

Dynamic Line Rating

Dynamic Line Rating (DLR) helps the network operator to dynamically assess the capacity of individual power lines and cables, in order to reduce the risk of line overloading during operation. This way, DLR allows that lines and cables fully utilize their maximum capacity for transmitting electric power.

In this deliverable, the potential of DLR will be studied for a MV grid with underground cables in the distribution network. The dynamic limits will be calculated based on measurements of the cable temperature. In this study we assume that a few spot measurements suffice, which represents a relatively low investment cost.

Demand Side Management

Demand side management (DSM) is a portfolio of measures to improve the energy system at the side of consumption, and can be categorized in the following: Energy Efficiency, Time of Use, Spinning Reserve and Demand Response. Demand Response (DR) can be described as the changes in electric usage by customers from their normal consumption patterns in response to changes in the price of electricity over time [1].

The focus of this deliverable will be on incentive-based demand response, more specifically the interruptible/curtailable programs. Based on feedback of the DSO (Eandis) participating in this study, this type of DR programs appears to be the most suitable for congestion avoidance. In these programs, customers receive an incentive in exchange for agreeing to reduce or increase their load in case of network congestion. The part of the distribution grid we used as input for our study (see section 2.2) is an industrial zone and as such the exact incentive details will be part of a commercial agreement with the industrial consumers. Nevertheless, different incentive mechanisms can be distinguished:

- Reservation fee: the DR-participant receives an incentive payment in function of the flexible amount of power demand he can offer, independent of the number and duration of the events during which the flexibility is requested — although obviously certain limitations will be included in the commercial agreement.
- Activation fee: the DR-participant will receive an incentive payment in function of the amount of flexible energy demand he offers, each time the flexibility is actually called upon.
- Combination of reservation and activation fee.

2.2 The Test Network

To compare the usefulness of the different proposed solutions (curtailment, DLR, DSM) from a technical and economical point a view, a number of analyses and simulations were performed for a real grid of Eandis with realistic production and consumption measurements.

This grid is located in the port of Antwerp, Belgium. It's an industrial zone containing a few solar panel parks, where since mid 2015 wind turbines are installed. Figure 1 gives an overview of the area with all identified locations for (future) wind turbines. For our analyses we assumed that 17 of those wind turbines would be connected to the local 15 kV MV grid.

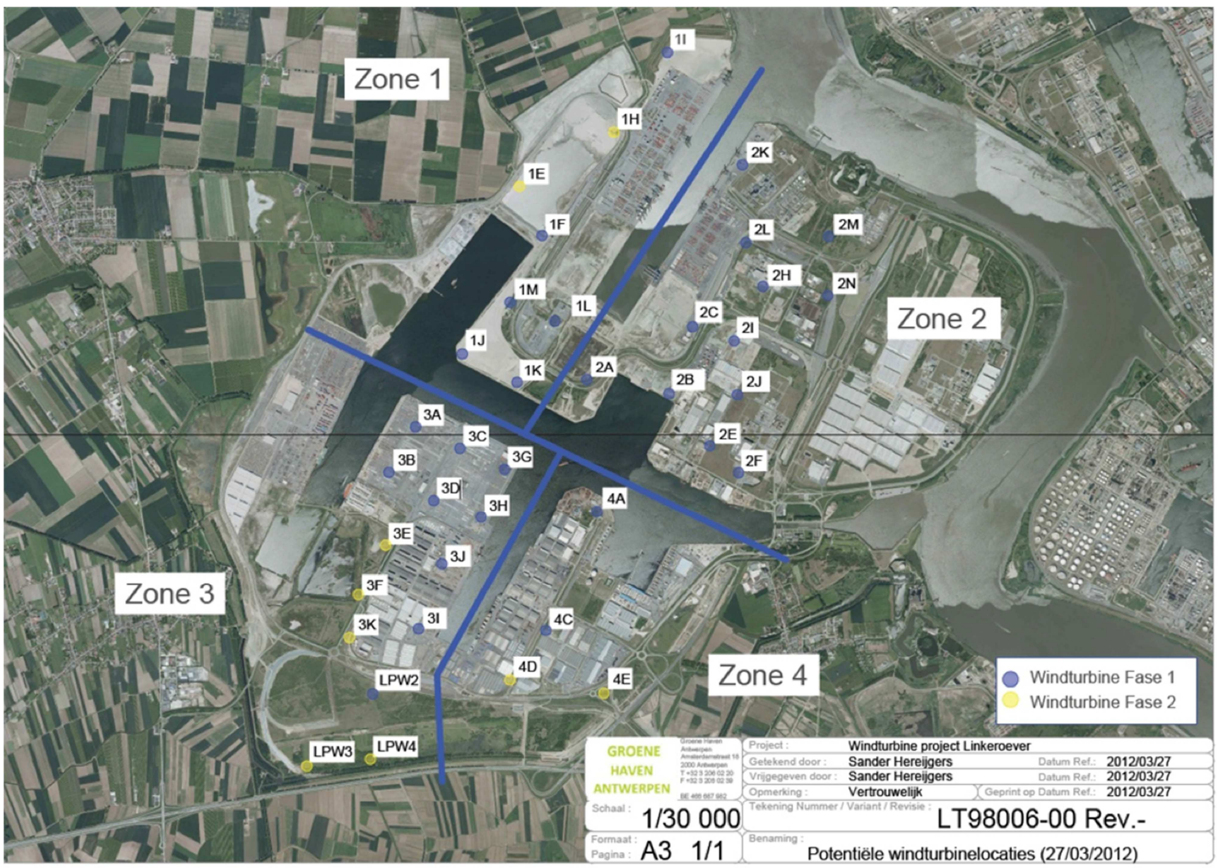

Figure 1. Eandis grid in the Port of Antwerp indicating all planned wind turbines

Figure 2 shows the single line diagram of those 17 wind turbines. 'TS Ketenisse' contains the HV/MV transformer.

We used the loads of the local companies and measurements from wind turbines in the neighbourhood as input consumption and production profiles for our simulations. These simulations, over a period of 1 year, revealed that the installation of these wind turbines will cause congestion issues in the grid, resulting in 5 wind turbines that need to be curtailed in order to avoid current congestion (blue dots) and voltage violations (orange dots). These 5 wind turbines are distributed over 4 feeders (labeled A/B/C/D).

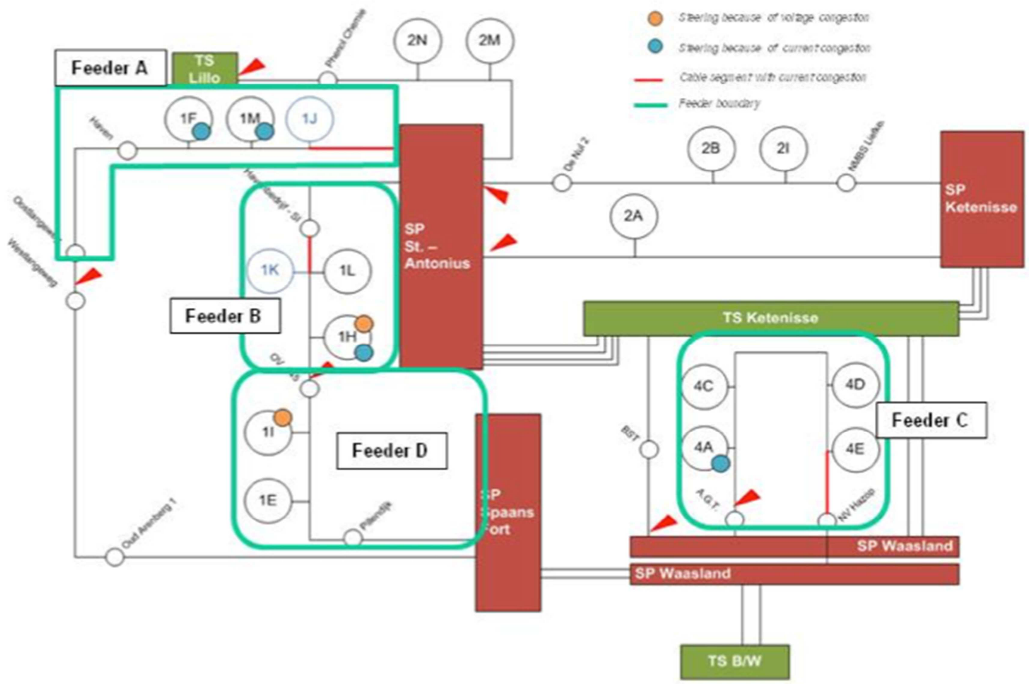

Figure 2. Single line diagram of the grid in the Port of Antwerp with 17 wind turbines

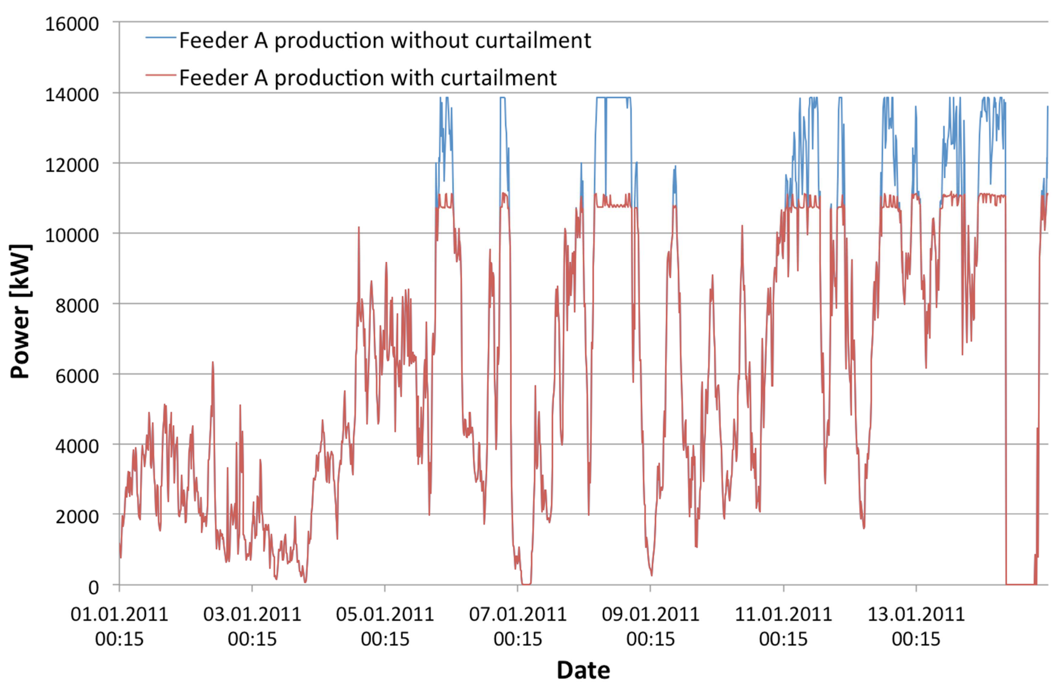

Figure 3. Example 2 week period of transmitted power over feeder A with and without curtailment

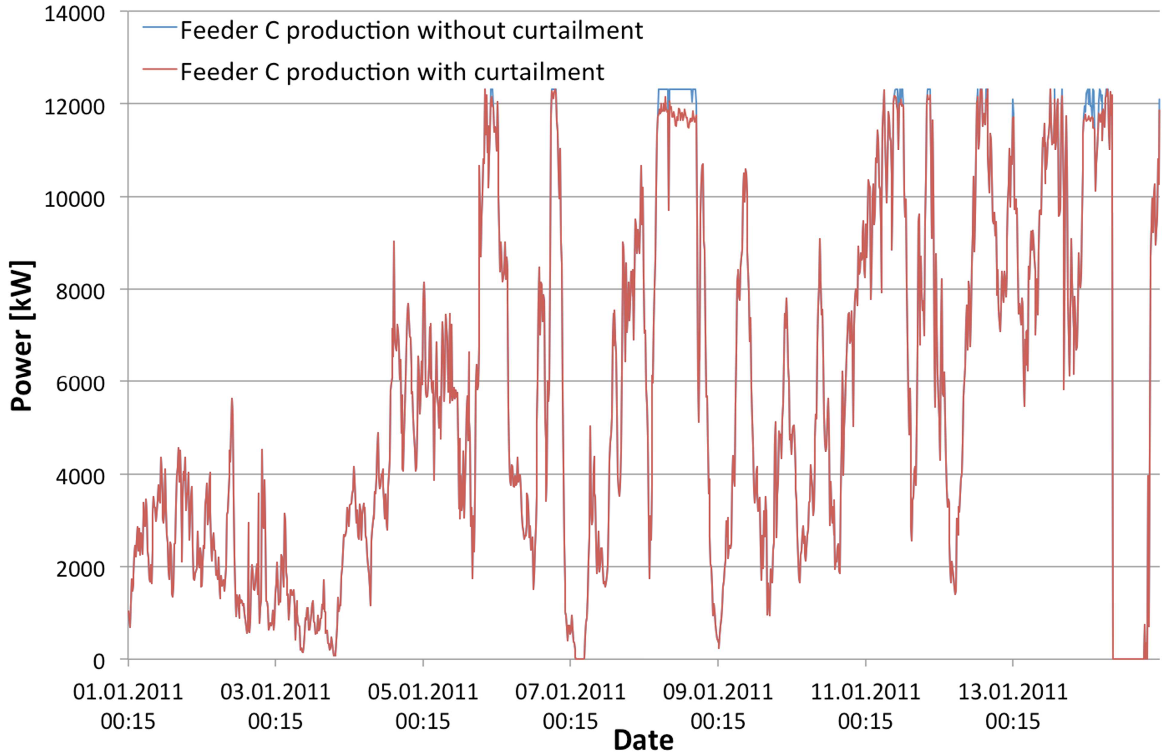

Figure 4. Example 2 week period of transmitted power over feeder C with and without curtailment

Figure 3 and Figure 4 show an example period of 2 weeks for Feeders A and C with a considerable amount of wind during that period. The blue line shows the amount of power transmitted over the feeder in case this feeder would be able to take up all injected energy. Network simulations of production and demand have shown voltage and/or current violations in some moments. In order to comply to the local grid constraints curtailment is necessary. It was calculated, based on the impact of the violation, what the maximum amount of current was that in that case could be injected. Simulations show that only the red amount of power can be transmitted over the feeder. For Feeder A, the amount of curtailed power is considerable whereas the amount of curtailed power for Feeder C is small. This is already an indication that a costly network investment might not always be the best option.

Table 1 provides a number of statistics for the 4 feeders for a studied period of 1 year, including the reason for, amount and duration of the curtailment events.

	Feeder A	Feeder B	Feeder C	Feeder D
Congestion type	Current	Current & Voltage	Current	Voltage
Length of congested cable segment (km)	1.25	0.79	1.08	6.95
Curtailed	2255	2176	281	2318

energy (MWh)				
% of feeder production	5.8	5.6	0.8	13.4
# of curtailment events	678	673	454	887
% of time	12.0	11.9	5.8	19.1
Max duration (h)	67.5	67.5	41.25	78.25
Max flex required (MW)	3.128	3.002	1.545	2.897

Table 1. Overview of congestion per feeder

2.3 Comparison of techniques via Investment Analysis

In D2.2 we presented a few simple business cases for the use of Dynamic Line Rating and Demand Side Management in comparison with grid investments from the viewpoint of a DSO, showing a.o. that DLR is interesting for existing cables, but not for new cables.

2.3.1 Compared options to address network congestion

In this section we present a more profound investment analysis for the discussed test network comparing the following 4 options to address network congestion:

- **Curtailment:**
  No specific investments will be made, so in case of congestion, the wind turbines need to be curtailed. In that case, the DSO could be assumed to compensate the wind turbine owner for these curtailments. This possible compensation based on lost energy includes an amount for both the energy that can't be sold and the Green Certificates the wind turbine owner can't claim due to the curtailment. Green Certificates represent the environmental value of renewable energy and are used by several countries (e.g., Belgium) to support the generation of green energy in a standardized way. For example, a wind turbine owner will receive green certificates corresponding to the production of the wind turbine for a period of 15 years. Another way of making a compensation could lie in the faster connection to the grid due to avoiding grid reinforcements or reduced connection cost (i.e. contracts including curtailment options). The loss of green energy is also from a social perspective not very desirable as we want to make our society as sustainable as possible.
- **Network reinforcement:**
  The DSO will invest in extra underground cables in order to avoid all congestion issues and corresponding curtailment. In this case, only the segment where the congestion issues occur is

reinforced. Still, the investments might be large to only solve a few congestion events per year. An extra benefit of this solution are reduced network losses due to the use of larger cables.

- **Dynamic Line Rating:**
  DLR equipment is installed on the underground feeder, allowing to avoid a part of the curtailment. DLR only offers a solution for current congestions and can't be considered in feeders with voltage violations only.
- **Demand Side Management:**
  DSM equipment is installed on several customer sites on the feeder, allowing to avoid a part of the congestion issues and corresponding curtailment. The availability of flexibility on the right locations is of course very dependent on the specific situation and flexibility products are typically tailored to reduce consumption whereas for this problem an increase of consumption is desired, so a number of assumptions were made.

2.3.2 Regulatory Framework Scenarios

Since the regulatory framework for congestion-induced wind-curtailment has not yet been clearly defined in Belgium, 4 different scenarios are studied:

- Scenario 1:
  - No limitations on the amount of curtailed energy per feeder.
  - The DSO is assumed to compensate for all curtailed energy.
- Scenario 2:
  - No limitations on the amount of curtailed energy per feeder.
  - No compensations for the first 2% of curtailed energy (on yearly basis).
- Scenario 3:
  - A maximum of 2% of curtailment is allowed (hard constrained).
  - No compensations for the first 2% of curtailed energy (on yearly basis).
- Scenario 4:
  - A maximum of 2% of curtailment is allowed (hard constrained)
  - The DSO is assumed to compensate for all curtailed energy

2.3.3 Costs & Benefits Overview

Overall, to compare the different options via a business case calculation, the following assumptions were made:

- The business case is calculated over a period of 20 years (N):
  - The initial investments are done in year 0 (not discounted).
  - The recurrent costs and revenues in year 1-20 (discounted).
- The NPV (Net Present Value) is used as evaluation method to compare the different business cases. This method uses the time value of money to appraise a long-term project. The NPV is calculated with a discount rate of 3.35% (i). This discount rate (or WACC – Weighted Average Cost of Capital) is relatively low, but is used in all investments analyses within

Eandis. R_t is the net cash flow (revenues minus costs) for the year t.

$NPV(i,N) = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$

- Regarding Green Certificates, we assumed the following:
  - Green Certificates have to be paid by the DSO both when the energy is produced by the wind turbine (normal way of working) and when the energy production is curtailed (as compensation payment).
  - For the different scenarios (see further), this implies the following:
    - **Scenarios 1 and 4:** Green Certificates (or compensations for green certificates) don't have to be taken into account.
    - **Scenario 2 and 3:** As the regulatory framework allows for 2% curtailment without any compensation (produced energy and green certificates), the avoided green certificates for the curtailment up to 2% has to be taken into account as a benefit (avoided cost) for the DSO.

In Table 2, an overview is given of the benefits and costs that are taken into account for the different options.

Solution	Benefits	One Time Cost	Recurrent Cost
Curtailment	Avoided green certificates (Sc.2&3)	/	Compensations to WT owner for lost revenues
Network Reinforcement	Reduction of network losses	Network infrastructure (new cables → 106 €/m)	/
Dynamic Line Rating	Avoided green certificates (Sc.2&3)	Temperature measurement equipment (1000€/feeder)	• DLR equipment maintenance • Remaining compensations to WT owner for lost revenues
Demand Side Management	Avoided green certificates (Sc.2&3)	DSM equipment (15000€/participant)	• Incentive payments to flex providers • DSM equipment maintenance • Remaining compensations to WT owner for lost revenues

Table 2. Overview of costs and benefits

The energy price and green certificate values are assumed to be €48.8/MWh and €68.8/MWh respectively, corresponding to the values used in the long term business evaluations by Eandis. As periods with network congestion are likely to have lower energy prices, a variable energy price over time might result in a more realistic business case. This could be interesting future research.

For Dynamic Line Rating, we assume that a few point measurements to monitor the temperature suffice, as installing a temperature measurement along the whole feeder is very expensive. This assumption will be validated via real-life experiments.

For Demand Side Management we had to make some assumptions on the incentive fees as current DSM products on the market are targeted at reducing consumption levels for wide areas, whereas for this use case we are looking for a local increase of the consumption. For the business case calculations we used an incentive fee of 30 €/MWh. We assume an installation cost of DSM equipment around 15k€/participant which corresponds to the typical cost of an RTU in distribution grids.

The availability of sufficient flexibility in the neighborhood will be very location dependent, so we had to make assumptions as well for this aspect. For our calculations we assumed that 80% of the congestion can be addressed with DSM solutions, using 3 flexibility providers and that flexibility is activated in blocks of 1 hour. As the congestion events are measured in blocks of 15 minutes, this means that a higher amount of flexible demand is activated than strictly needed. However, it is not very likely that flexible loads can be controlled with a fine-grained granularity of 15 minutes, therefore our assumption of using blocks of 1 hour.

It is likely that there will be a reduced (or increased) demand of the DSM-participant after the congestion event, i.e., the so-called rebound effect. This rebound effect is assumed not to cause network congestion at a later point in time. Furthermore, we did not take into account the exact location of the flexible load on the feeders.

Table 3 shows an overview of the amount of energy that still has to be curtailed after introduction of the respective solution.

	Feeder A	Feeder B	Feeder C	Feeder D
Curtailment	100%	100%	100%	100%
Network reinforcement	0%	0%	0%	0%
DLR	31.42%	11.93%	61.84%	100% (DLR not applicable for voltage violations)
DSM (assumption)	20%	20%	20%	20%

Table 3. Percentage of (remaining) curtailed energy per solution

2.3.4 Results

2.3.4.1 Feeder A

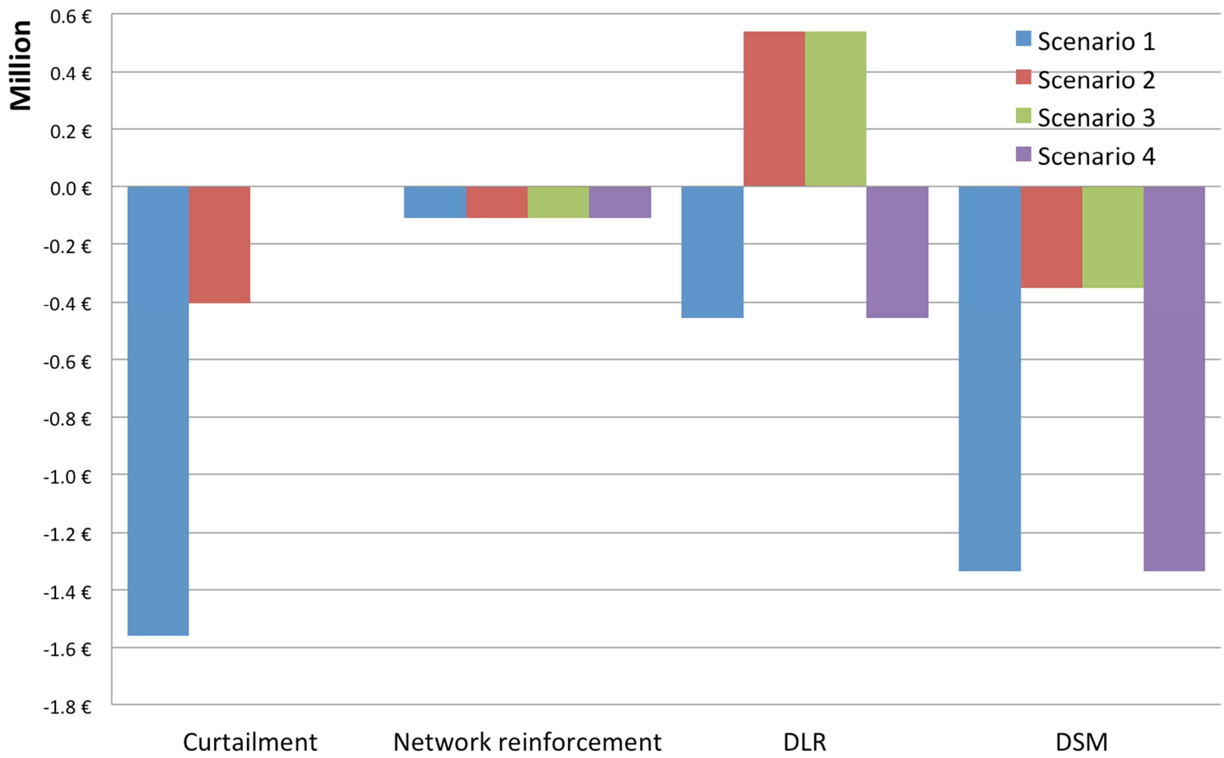

Figure 5. Business case results for Feeder A

As outlined in section 2.2 5.8% of the total energy production of the wind turbines connected to Feeder A needs to be curtailed to avoid any congestions. This means that curtailment only is not applicable for scenarios 3 & 4 as the maximum allowed curtailment is hard constrained to 2% in these scenarios.

Network reinforcement has the same cost in all scenarios, as all congestion is solved and thus no compensations need to be paid, and is the most profitable solution in scenarios 1 & 4, the cases where the DSO has to compensate all lost energy to the wind turbine owner.

With DLR & DSM a considerable amount of congestion can be solved, but still some compensations need to be paid for the remaining curtailed energy, depending on the scenario. For feeder A enough congestion can be solved to stay below the 2% limit, which means that in scenarios 2 & 3 no compensations need to be paid and the DSO saves money on avoided green energy certificates. In case of DSM there is still the cost for paying the flex providers for shifting their consumption and the installation and maintenance costs for the DSM equipment. In case of DLR the business cases are even positive as the benefits of avoided green energy certificates are higher than the installation and maintenance costs of the DLR equipment. For these scenarios DLR is cleary the best option.

2.3.4.2 Feeder B

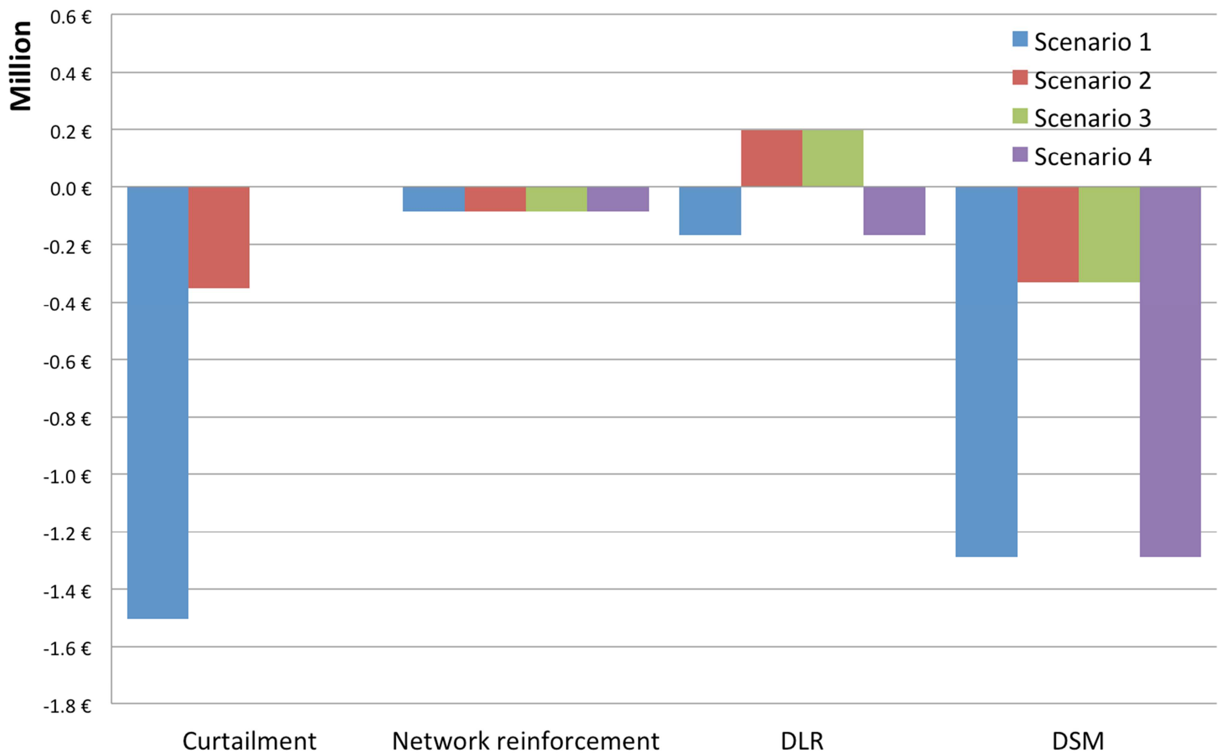

Figure 6. Business case results for Feeder B

The results for Feeder B are quite similar to Feeder A. On this feeder a total of 5.6% of the total energy production needs to be curtailed to avoid any congestions. So again, curtailment only is not applicable for scenarios 3 & 4 as the maximum allowed curtailment is hard constrained to 2% in these scenarios.

The network reinforcement cost is a bit lower than for Feeder A as the to be reinforced cable is shorter. Again network reinforcement is the cheapest option in case the DSO has to compensate all curtailed energy.

For scenarios 2 & 3, the business case for DLR is positive just as for Feeder A, but not as pronounced, as DLR can in fact solve quite a lot of curtailment on Feeder B. After applying DLR, the amount of curtailed energy on Feeder A drops from 5.8% to 1.8%, while on Feeder B the amount of curtailed energy drops from 5.6% to 0.7%. As less energy is curtailed, less money is saved on Green Energy certificates. For these scenarios the best business case for the DSO would be to stop applying DLR when the threshold of 2% is reached, but that is not the best option from a societal point of view of course.

2.3.4.3 Feeder C

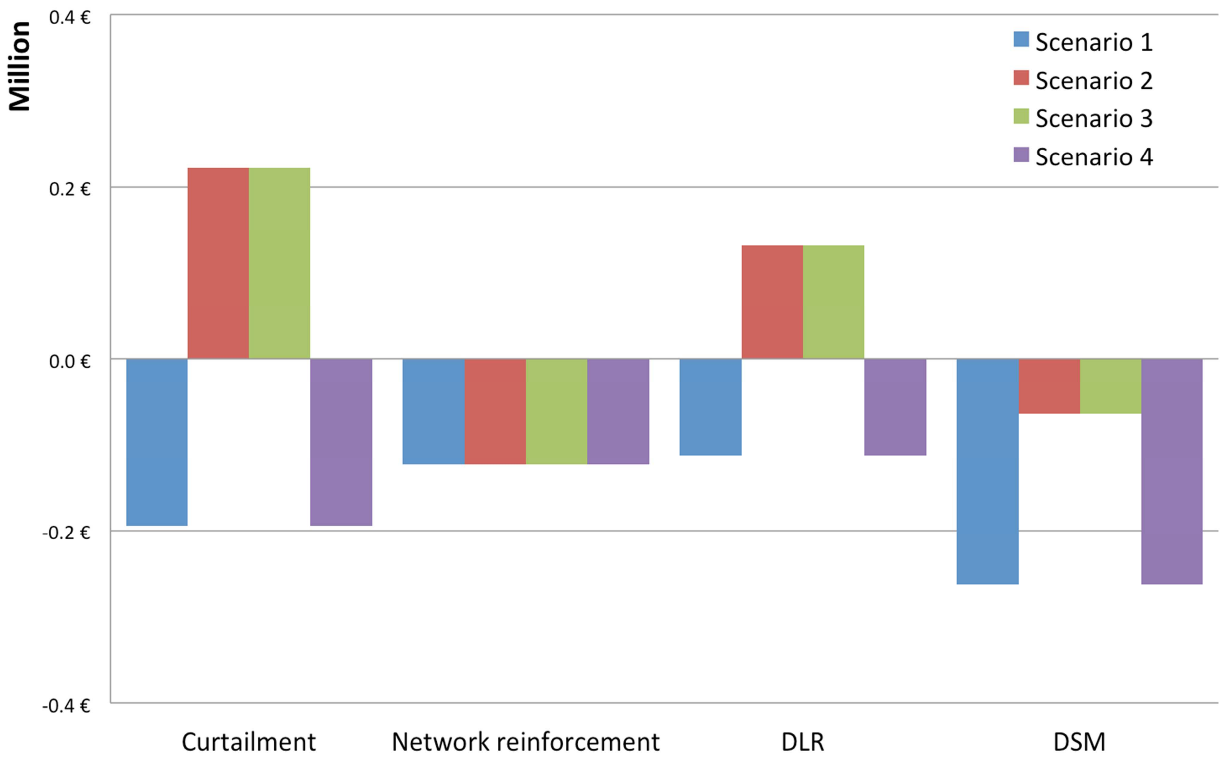

Figure 7. Business case results for Feeder C

The amount of congestion on Feeder C is low. Without any measures only 0.8% of the total production on that feeder needs to be curtailed. This means that curtailment only is also an option in scenarios 3 & 4. In scenarios 2 & 3 (where no compensations are needed for the first 2% of curtailment), curtailment is clearly the best option, as there are the benefits of avoided Green Energy certificates for the DSO, but no costs. Again, if we look at this from a purely economical point of view, the DSO could even curtail more, up to 2%, even if it's not necessary, to save extra money on avoided Green Energy certificates.

In scenarios 1 & 4, DLR is now a little more profitable than network reinforcement. After applying DLR only about 0.5% of the total energy production on that feeder still needs to be compensated. This compensation (+ DLR equipment costs) is cheaper than investing in new feeders.

As curtailment is quite cheap for this feeder due to the low amount of congestion events, DSM is in fact the worst option in scenarios 1 & 4. In scenarios 2 & 3 however, DSM is cheaper than network reinforcement.

2.3.4.4 Feeder D

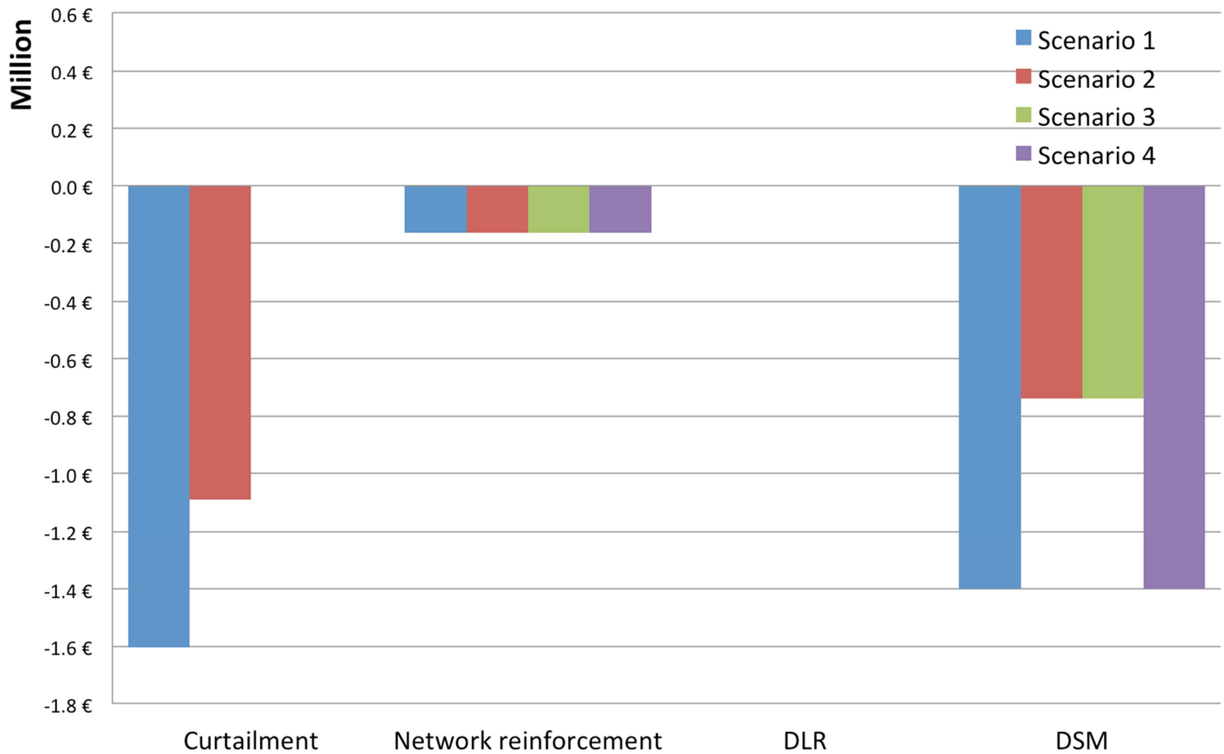

Figure 8. Business case results for Feeder D

Feeder D has the highest amount of congestion, with a total of 13.4% of the total production that needs to be curtailed if no other measures are taken. All congestion is also caused by voltage issues, which means that DLR is no option here as DLR can only solve current congestions. Network reinforcement is clearly the best option, which is obvious with such a high amount of congestion events.

2.3.4.5 DLR vs network reinforcement in function of cable length

	Feeder A	Feeder B	Feeder C	Feeder D
Segment length	7666 m	2245 m	939 m	Not applicable

Table 4. Cable length corresponding to tipping point between DLR and network reinforcement business cases.

Overall DLR (with point measurements) can be considered as the economically most interesting ANM technique. For some scenarios and feeders DLR is even more profitable than the network reinforcement case. An important parameter that determines the profitability of DLR vs network reinforcement is the length of the network segment that needs to be reinforced. Therefore, we have calculated the theoretical tipping point, i.e., the segment length for which the DLR business case becomes more profitable than network reinforcement (for scenarios 1 & 4 where all curtailed energy needs to be compensated). The results can be found in Table 4. It can be seen that the tipping point is relatively lower in case the amount of required flexibility is low (as in Feeder C) or when the percentage of curtailment that can be avoided with DLR is high (as in Feeder B).

2.4 Conclusions

Based on the investment analysis presented we were able to derive a number of rules of thumb for the different analyzed options:

Network Reinforcement is often the most interesting option. When investing in new grid segments the DSO should always install equipment that can guarantee an injection of all produced energy at all times. In most cases, the extra equipment costs are low in comparison with the digging costs that are necessary anyway. Also when the to be connected DRES will cause a considerable amount of congestion, grid reinforcements are the way to go. Network reinforcement has also the added benefit of reduced network losses. A disadvantage is that such network reinforcements might take time and thus the connection of the DRES might be delayed.

Dynamic Line Rating is an interesting option to solve current congestions. It’s a valid alternative to network reinforcement if the to-be-reinforced cable segment is considerably long or the number of congestions is relatively low.

DLR is especially suited to solve short congestion peaks (as after a while the temperature of the feeder will become too high) and thus could be interesting as a first buffer until e.g. flexible loads are activated to further mitigate long congestions events.

For our analysis, we assumed that a few point measurements are enough to monitor the feeder temperature. This cheap option still needs to be validated with real-life tests. The alternative of adding a fibre cable along the feeder to measure the temperature is of course much more expensive as this involves similar digging costs as with network reinforcement.

Demand Side Management seems to be a rather expensive option in our analysis, only a bit cheaper than the curtailment option in most scenarios. However, we made some assumptions based on currently available DSM products and energy prices. Current DSM incentive schemes are meant for temporally decreasing consumption, where in our case a local increase of the load is what we are looking for. There is clearly a need for custom products to deal with congestion issues on DSO level and to reward consumption increases.

Furthermore, if variable energy prices would be common, periods with network congestion are likely to have low energy prices (as the production of DRES is high) and this would already be an incentive for local consumers to shift their load to such periods (even without extra DSM incentives). This could clearly make the DSM business case more profitable, but needs further research.

Advantages of DSM are that it can solve voltage violations and that the produced green energy is effectively used (in contrast with curtailment). A clear disadvantage is the strong dependence on locally available flex providers. So every case will be different.

Curtailment of green energy sources is often not allowed yet, as green energy gets priority over other types of energy, but it could be an interesting option as well in some cases. When the expected amount of congestion events is low, curtailment could allow a fast connection of new DRES sources to existing grids. When a smart curtailment control system is used that can send fine-grained set points to the DRES sources, the impact for the DRES owner could be very limited, and in some cases be even positive. With such a system it might be possible to keep injecting energy during abnormal net conditions (N-1 situations), which would not be possible otherwise.

This analysis focused on the integration of new DRES in existing distribution grids from a planning perspective. If the DSO decides to install one or more ANM systems in its grid, it's of course essential to choose the best ANM option in real-time when operating such a smart grid. This requires accurate DRES power production and local load **predictions.**

The business cases clearly depend on the **regulatory framework**. So, further work is needed on this aspect to e.g. define to what extent curtailment is allowed and compensated.

3 Coordinated OLTC Control in MV Grids based on State Estimator

3.1 Background and Current Situation

The goal of voltage regulation in the Medium Voltage (MV) grids is to keep the actual voltage level $U_{\mathrm{PoC},i}$ at each point of connection (PoC, which could be a MV/LV substation or MV connection point to a large industrial consumer) as close to the (predefined) reference voltage level $U_{\mathrm{PoC,ref},i}$ as possible [1]. This can be achieved by optimizing the tap-positions $\boldsymbol{\kappa}$ of HV/MV (typically 150kV/10kV) and MV/MV (10kV/10kV regulating substations to compensate voltage drops along long 10kV cables) transformers, defined in (1).

$$\boldsymbol{\kappa} = [\kappa_m], 1 \le m \le N_T \tag{1}$$

where:

κ_m	tap position at m^{th} HV/MV or MV/MV transformer, which is an integer and within the range $\kappa_{m,\min} \le \kappa_m \le \kappa_{m,\max}$
N_T	total number of HV/MV or MV/MV transformers

Traditionally, the tap positions of the HV/MV transformers are controlled by the automatic voltage regulator (AVR), as shown in Fig. 1. The controller is a closed-loop system which compares the voltage (measured) on the MV bus with the reference voltage. Since the tap changer position is a discrete quantity with fixed steps, a dead band is used.

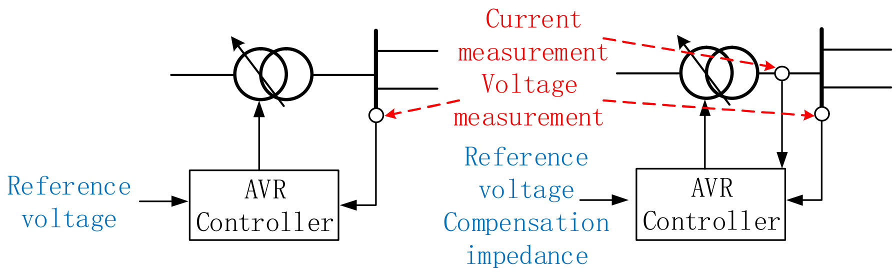

Fig. 1 Automatic voltage regulator a) without and b) with line drop compensation

Two classical control methods can be employed in the OLTC operation.

- The simplest control is to keep the voltage at busbar within a tolerance range, without considering the load condition (Fig. 1a).
- To reduce the voltage variation in MV grid when load changes, line drop compensation is introduced [2]. It also takes the load current from the transformer to the MV busbar into account, with the compensation impedance (Fig. 1b).

The classical methods only considers the total transformer current into account, i.e. the distribution of the loads and Decentral Generation units (DGs) along the MV feeders are not considered. Moreover, there is no coordination between the main transformer (HV/MV) and the regulating transformers (MV/MV). Several researches aimed to solve the problem by introducing voltage control at MV/LV substations [3-6] to compensate voltage violations on MV level. However, this increases the investment of the grid operators dramatically, due to the large number of MV/LV substations.

3.2 Proposed Method

In an operation framework based on an state estimator, the real-time state of the grid can be known from the state estimator, including the estimated real-time power flow $\underline{\mathbf{S}}_{\mathrm{est}}$ at each PoC. The weighted average voltage quality deviation ΔU can be defined as a function of $\underline{\mathbf{S}}_{\mathrm{est}}$ and the tap position vector $\boldsymbol{\kappa}$, shown in (2). The voltage deviation at each PoC can be weighted by the importance factor η_i, which is higher for the PoC with lower tolerance for the voltage level variation. For example, for an industrial PoC where an advanced voltage controller is installed inside the factory, the importance factor can be lower because the voltage variation can still be controlled in the factory. For a residential PoC with a fixed ratio MV/LV transformer, the importance factor may be a bit higher.

The coordination between the transformers can be achieved by including this importance factor.

$$\Delta U(\boldsymbol{\kappa}, \underline{\mathbf{S}}_{\text{est}}) = \sqrt{\frac{\sum_{i=1}^{N_{\text{PoC}}} \eta_i [U_{\text{PoC},i}(\boldsymbol{\kappa}, \underline{\mathbf{S}}_{\text{est}}) - U_{\text{PoC,ref},i}]^2}{\sum_{i=1}^{N_{\text{PoC}}} \eta_i}} \tag{2}$$

where:

Symbol	Explanation
ΔU	weighted average voltage quality deviation, with respect to the tap-positions $\boldsymbol{\kappa}$ and power flow $\underline{\mathbf{S}}_{\text{est}}$
$\boldsymbol{\eta_i}$	importance factor, representing the voltage control priority
$\boldsymbol{U_{PoC,ref,i}}$	predetermined target (ideal) voltage level at the i-th PoC
$\boldsymbol{U_{PoC,i}}(\boldsymbol{\kappa}, \underline{\mathbf{S}}_{est})$	resulted voltage level (by power flow calculation) at PoC i, with respect to $\boldsymbol{\kappa}$ and $\underline{\mathbf{S}}_{\text{est}}$

To optimize the tap-positions $\boldsymbol{\kappa}$ regarding to the estimated real-time power flow $\underline{\mathbf{S}}_{\text{est}}$, an integer nonlinear programming problem is defined in (3). With the optimized $\boldsymbol{\kappa}$, the coordination between HV/MV and MV/MV transformers can be achieved, where traditionally only the HV/MV transformer is controlled. Furthermore, the priority of voltage control for different nodes is considered.

$$\begin{aligned} & \min_{\boldsymbol{\kappa}} \Delta U \\ \text{s.t.} \quad & \kappa_m \in \mathbb{Z}, \quad m = 1 \sim N_T \\ & \kappa_{m,\min} \le \kappa_m \le \kappa_{m,\max}, \quad m = 1 \sim N_T \end{aligned} \tag{3}$$

3.3 Decoupled Nonlinear Integer Programming

It is difficult to solve the optimization problem in (3) analytically, because the function $\Delta U(\boldsymbol{\kappa}, \underline{\mathbf{S}}_{\text{est}})$ is nonlinear and has no explicit formula (iterative method needed for power flow calculation). However, as shown in Fig. 2, in a radial distribution grid the coupling is very weak between the voltages at the MV buses directly connected to the main HV/MV transformers and the tap positions of other MV/MV regulating transformers. Therefore, the problem can be decoupled to optimize the tap position of each transformer individually. The partial sum of ΔU is defined in (4), considering the PoCs only directly connected to the m^{th} transformer.

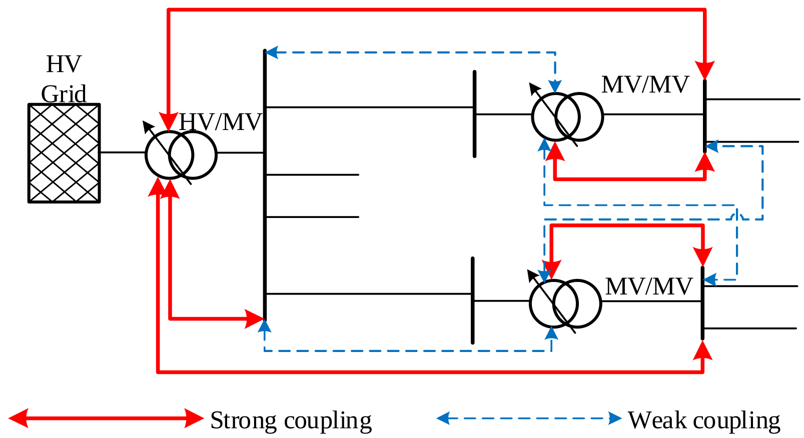

Fig. 2 Coupling between MV buses and tap position of transformers

$$\Delta U_m(\kappa_m, \boldsymbol{\kappa}_{*m}, \underline{\mathbf{S}}_{\text{est}}) = \sqrt{\frac{\sum_{i \in \mathrm{V}_m} \eta_i [U_{\text{PoC},i}(\boldsymbol{\kappa}, \underline{\mathbf{S}}_{\text{est}}) - U_{\text{PoC,ref},i}]^2}{\sum_{i \in \mathrm{V}_m} \eta_i}} \tag{4}$$

where:

ΔU_m	partial sum of ΔU, considering the PoCs only directly connected to the m^{th} transformer
$\boldsymbol{\kappa}_{*m}$	part of $\boldsymbol{\kappa}$ excluding the component κ_m
V_m	set of the PoCs which are directly connected to the m^{th} transformer

The minimization problem can be decoupled and solved using the procedure below:

1. Set $\boldsymbol{\kappa}$ to the default values (default tap positions).
2. Keep all the components in $\boldsymbol{\kappa}_{*1}$ as constants, calculate the partial sum $\Delta U_1(\kappa_1, \boldsymbol{\kappa}_{*1}, \underline{\mathbf{S}}_{\text{est}})$ with all possible values of the tap position κ_1 of the main HV/MV transformer (which is assumed to have sequence number 1). Select and assign the optimized value to κ_1 so that $\Delta U_1(\kappa_1, \boldsymbol{\kappa}_{*1}, \underline{\mathbf{S}}_{\text{est}})$ is at minimum.
3. Let $m = 2$, start to optimize the tap positions of regulating transformers.
4. Keep all the components in $\boldsymbol{\kappa}_{*m}$as constants, calculate the partial sum $\Delta U_m(\kappa_m, \boldsymbol{\kappa}_{*m}, \underline{\mathbf{S}}_{\text{est}})$ with all possible values of the tap position κ_m of the m^{th} MV/MV regulating transformer. Select and assign the optimized value to κ_m so that $\Delta U_m(\kappa_m, \boldsymbol{\kappa}_{*m}, \underline{\mathbf{S}}_{\text{est}})$ is at minimum.
5. If $m = N_T$, stop and optimized tap positions $\boldsymbol{\kappa}$ is obtained, otherwise $m = m + 1$ and go to Step 4.

3.4 Performance Indices

To evaluate the performance of the voltage regulation, two performance indices $\mathrm{P}_{U,\mathrm{opt}}$ and $\Delta U_{\mathrm{diff,max}}$ are proposed [7]. The performance indices are calculated from Monte Carlo simulations [8]. In each simulation case, the following calculations are performed.

1. Minimize $\Delta U(\boldsymbol{\kappa},\underline{\mathbf{S}}_{\mathrm{est}})$ with the estimated power flow, resulting in the estimated optimal tap position $\boldsymbol{\kappa}_{\mathrm{opt,est}}$ and the voltage deviation $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,est}},\underline{\mathbf{S}}_{\mathrm{est}})$.
2. Minimize $\Delta U(\boldsymbol{\kappa},\underline{\mathbf{S}}_{\mathrm{real}})$ with the real power flow, resulting in the real optimal tap position $\boldsymbol{\kappa}_{\mathrm{opt,real}}$ and the voltage deviation $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,real}},\underline{\mathbf{S}}_{\mathrm{real}})$.
3. Check if $\boldsymbol{\kappa}_{\mathrm{opt,est}}$ matches $\boldsymbol{\kappa}_{\mathrm{opt,real}}$.
4. If they don't match, calculate the voltage deviation with estimated optimal tap positions and real power flow, i.e. $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,est}},\underline{\mathbf{S}}_{\mathrm{real}})$, and compare it with $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,real}},\underline{\mathbf{S}}_{\mathrm{real}})$.

The results from all Monte Carlo simulation cases are aggregated. The performance index $\mathrm{P}_{U,\mathrm{opt}}$ is defined as the probability that $\boldsymbol{\kappa}_{\mathrm{opt,est}}$ matches $\boldsymbol{\kappa}_{\mathrm{opt,real}}$. In addition, $\Delta U_{\mathrm{diff,max}}$ is defined as the maximum difference (at a confidence level of 99%) between $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,est}},\underline{\mathbf{S}}_{\mathrm{real}})$ and $\Delta U(\boldsymbol{\kappa}_{\mathrm{opt,real}},\underline{\mathbf{S}}_{\mathrm{real}})$.

3.5 Simulation Results

This section presents a case study on a typical European MV distribution grid topology for OLTC control. Firstly, the OLTC control is simulated using the traditional AVR method, and the performance indices are calculated. Then the OLTC control is simulated using the state estimation approach with optimized meter placement.

The sample grid in the case study is downsized and anonymized from a real MV grid OS Zaltbommel, owned by Alliander N.V., a Dutch distribution grid operator which manages around 1/3 of the MV grids in Netherlands. As shown in Fig. 3, the MV grid is divided into three parts: the sub-grid directly connected to 150/10kV main substation (Bus 2), the sub-grid connected to the 10/10kV regulating substation (Bus 4), and the sub-grid connected to the 10kV switching substation (Bus 5). There are 74 MV PoCs, among which six PoCs are connected to industrial loads and three PoCs are connected with DGs. The others are used for household/commercial loads.

In this scenario the MV/MV transformer is set to a neutral position and first the tap position of the HV/MV transformer is optimized. Next, this tap position is fixed and the tap position of the MV/MV transformer is optimized. In this case there is only one MV/MV transformer, if there would have been more, these transformers would be optimized one by one.

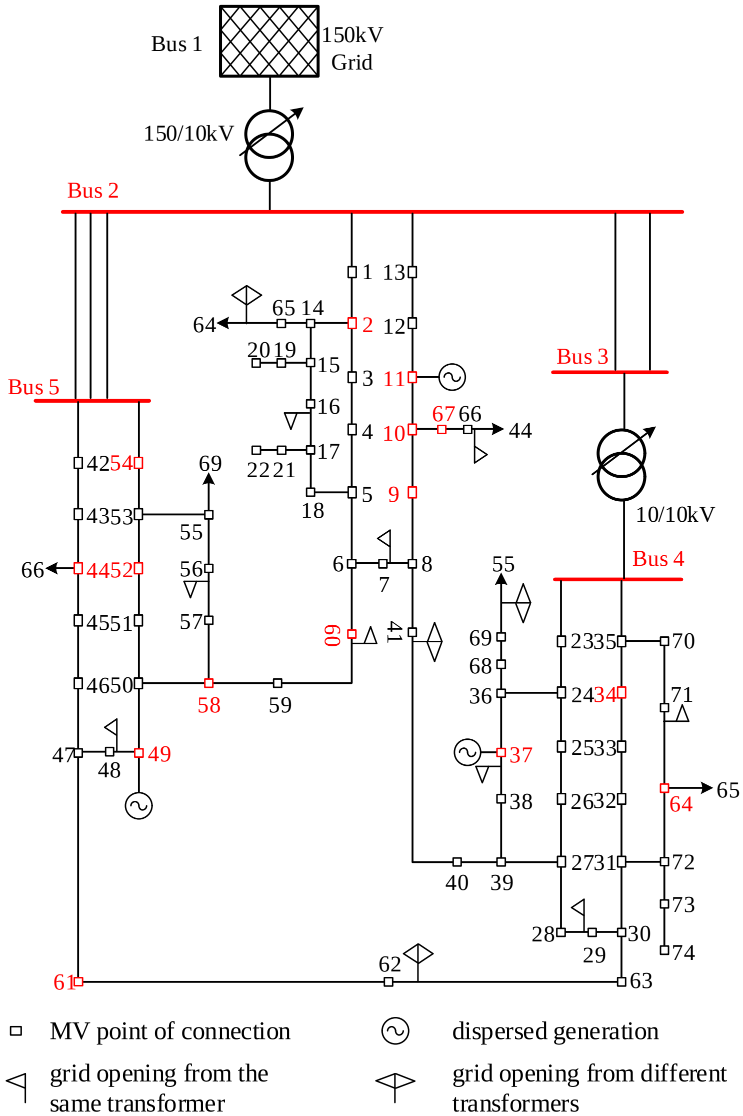

Fig. 3 Structure of typical European distribution grid, with the red-marked PoCs and busbars in the optimized measurement scheme

3.5.1 Current Strategy

The simulation is firstly performed with traditional AVR control for OLTC at the main HV/MV transformer. The performance indices are: $P_{U,\text{opt}} = 12.3\%$, $\Delta U_{\text{diff,max}} = 0.149kV$. In only 12.3% of the cases, the theoretical optimal tap positions can be achieved using AVR. This is far below the voltage-control potential of the transformers.

3.5.2 Proposed Method

The simulation is performed using state estimation approach with optimized meter placement. The performance indices are: $\mathrm{P}_{U,\mathrm{opt}} = 95.7\%$, $\Delta U_{\mathrm{diff,max}} = 0.0037kV$. Fig. 4 shows the comparison of performance indices between traditional method and proposed method. The theoretical optimal tap positions can be now achieved in 95.7% of the cases. Meanwhile the other index $\Delta U_{\mathrm{diff,max}}$ is also improved significantly.

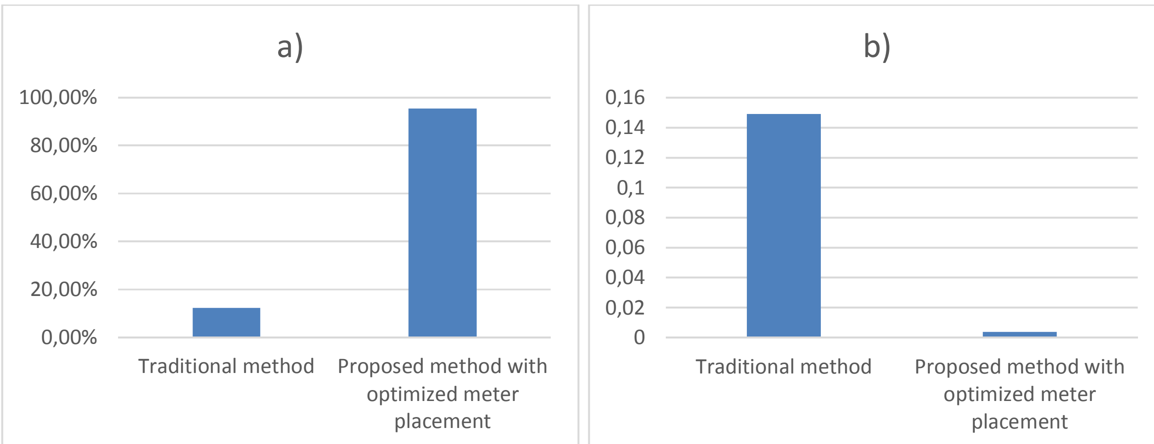

Fig. 4 Comparison between traditional method and proposed method with optimized meter placement, for performance indices a) $\mathrm{P}_{U,\mathrm{opt}}$ and b) $\Delta U_{\mathrm{diff,max}}$.

3.6 Conclusion

Unlike the traditional method that only considers the total current of the transformer, the proposed OLTC control includes the distribution of load currents. Moreover, the coordination between main HV/MV transformer and MV/MV regulating transformers is realized. The simulation results demonstrate the feasibility of the proposed method and the potential improvements.

This approach could in principle also be used for MV/LV transformers with OLTC, if the LV grid is treated as a single large load. However, to fully utilize the advantage of OLTC at the MV/LV transformer, state estimation in LV grids is needed.

4 References

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