The Activation of Congestion Service Contracts for Budget-Constrained Congestion Management

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***Abstract*—Several European distribution system operators (DSOs) are currently grappling with network congestion. New Dutch grid codes have specified two novel bilateral contracts for flexibility procurement from congestion service providers (CSPs), and a budget DSOs can spend on these contracts together. This paper provides the first formalization of these capacity restriction contracts (CRCs) and redispatch contracts (RCs) and presents an optimization model to guide DSOs in allocating a budget between these contracts. In the model, the contracts are activated sequentially by solving two linked (mixed-integer) second-order cone programming problems, where the first is a bi-level leader-followers game between the DSO and CSPs. Applying the model to a Dutch low-voltage network shows that adopting a mix of the two instruments is most cost-effective. It was also shown that if contracted parameters are not chosen properly, the national day-ahead and intra-day market prices can significantly impact the DSOs ability to apply congestion management.**

***Index Terms*—Congestion Management, Distribution Systems, Flexibility, Bilateral Contracts, Optimization**

I. Introduction

The increasing penetration of (renewable-based) distributed energy resources (DERs) in medium and low voltage (LV) networks poses new challenges for distribution system operators (DSOs) worldwide. Emerging trends like the electrification of heating and mobility, combined with the increase of volatile and local generation, can lead to larger, bidirectional, and less predictable power flows. This increases the risk of congestion in the distribution grid. As a result, DSOs in several European countries, such as Germany [1] and the Netherlands [2], currently grapple with this problem.

A. Related Work

In addition to traditional grid reinforcements, numerous alternative strategies revolving around flexibility from DERs to tackle congestion have been proposed in both academic studies and real-world applications [3][4]. In these approaches, DSOs invoke instruments to incentivize flexible demand and production to change their set points. There is an extensive body of literature proposing instruments of various types for this purpose. For example, several works discuss and compare tariff instruments like time-of-use tariffs, critical peak pricing, locational-based pricing, and power-based pricing [5][6][7]. Many others introduce new electricity and flexibility market designs [8][9][10], whereas others focus on non-market-based instruments, like grid reconfiguration, curtailment, and active/reactive power control [11][12][13].

In reality, several of these different instrument types could co-exist, resulting in multiple instruments available for congestion management to the DSO at different moments in time. There could be advantages to such an approach, as Shen *et al* demonstrates that combining a dynamic tariff, grid reconfiguration, and a reprofiling product sequentially, prevents very high dynamic tariffs for consumers/aggregators [14]. A hierarchical control scheme was developed in [15], in which a control layer applied both a network reconfiguration method and a flexibility reprofiling product. In addition, active power curtailment was used in [16] to complement a flexibility market. What we do observe in these studies, however, is that they either focus on congestion management instruments that can only be applied before day-ahead (DA) market closing, or use instruments that may cause imbalance in the system when flexibility is procured. Furthermore, most redispatch/reprofiling products assume that the DSO buys/sells energy from the flexibility providers, which is not allowed in some EU-member states. Lastly, the studies focus on providing congestion management under minimal total costs, but do not consider how to distribute a budget, given that the congestion management is budget-constrained.

B. Contribution

In this study, we explore the latest grid codes in the Netherlands implemented in 2022, which provide DSOs with more legal freedom to address congestion with flexibility [17]. The code formally defines the role of a congestion service provider (CSP), and two types of bilateral contracts for flexibility provision. The two contracts, defined in more detail in section II, should be arranged with a CSP and need to be activated the day before the congestion is expected. The capacity restriction contracts (CRCs) are an example of non-firm connection agreements and need to be activated a few hours before the day-ahead (DA) market closes, while the redispatch contracts (RCs) are activated after the DA-market closes. This is also illustrated in Fig. 1. Moreover, the grid codes also dictate that the DSOs have some yearly

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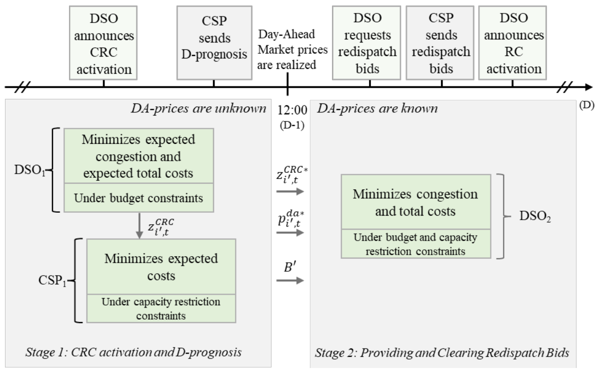


Fig. 1. The top part shows an indicative timeline for the DSO-CSP interaction regarding the activation of the capacity restriction contracts and redispatch contracts for congestion management. The bottom part shows the corresponding schematic for the optimization model proposed in section III.

budget they should spend on congestion management before they can start denying parties new grid connections [17]. That being said, it is currently not clear to what extent this budget covers the actual costs of congestion management; how this budget can best be distributed over the two instruments in the contract activation phase; and what incentives to provide in the contracts.

To address both the established gap in the literature and this need from DSOs, the paper makes the following contributions:

- The first formalization of capacity restriction contracts and redispatch contracts that complies to the Dutch grid codes. This formalization describes the operational aspects of these novel bilateral contracts, which can be strategically applied in two distinct time stages for effective day-ahead and intra-day congestion management. Moreover, it ensures that DSOs do not engage in energy trading activities causing system imbalances; and incentivizes load shifting over curtailment.
- An optimization model to study the effects of budget allocation and contracted incentives over the two formalized contract types. The model consists of two linked (mixed-integer) second-order cone programming problems, where the first is a Stackelberg game between the DSO and the CSP.
- Since the redispatch contract costs and incentives depend on both the DA- and intra-day (ID) market prices, its effect on the DSOs ability to provide congestion management is demonstrated in a case study.

It should be noted that though our study is specifically designed for the new situation in the Netherlands, we can expect DSOs to face similar decision problems in other countries in the future. Non-firm capacity agreements like CRCs have already been legalized in e.g. France and Norway [18]. Furthermore, various platforms for market-based redispatch are emerging in Europe [4]. This work can thus be viewed more broadly as a first approach for coordinating new capacity agreements with redispatch for effective congestion management.

The remainder of the paper is organized as follows. The capacity restriction contract and redispatch contract are discussed in section II. Then, the models for the DSO and CSP decision-making are treated in section III. Afterward, the results of a case study are discussed in section IV, and section V summarizes the conclusions of this paper.

II. Congestion Management Budget and Contracts

DSOs in the Netherlands now have access to two new contract types for congestion management in congestion areas: capacity restriction contracts and redispatch contracts [17]. Contracts can be signed with either a Congestion Service Provider (CSP) or, in the case of a CRC, with (large) individual connections. The CSP is a new entity aggregating the flexibility from several connections in a congested area to provide congestion management services to the DSO. To prevent unnecessarily high social costs, the grid codes introduce a financial limit for DSOs to spend on congestion management before they can stop granting new connections to the grid. In practice, we should thus not interpret this financial limit as the maximum amount a DSO *is allowed* to spend on congestion management using the contracts, but rather the minimum amount they *need* to spend. In this work, we will consider DSOs that don't spend more than this minimum financial limit. For these DSOs, the financial limit can be considered to be a budget B to distribute over the two contracts The financial limit is currently set to 1.02 €/MWh times the maximum energy capacity that the congested network can annually transport. The available transport capacity is determined by the capacity of the constraining grid element [17]. The two contract types are now discussed in more detail.

A. Capacity Restriction Contracts

A CRC entails that a connected party limits its transport capacity from its physical capacity to some lower contracted capacity in exchange for payment. This aids in resolving anticipated congestion for the following day. The contract specifies the contracted capacities for the individual connections, a compensation scheme, and possibly the times at which the contract will be activated. The latter is not required, as DSOs can also decide to announce the contract activation at the connections/future time steps for the next day a few hours before the closing of the DA-market. Note that this way no system imbalance is introduced by the activation of the contracts. Given some expected congestion on day D, the activation of the CRCs takes place at $D-1$ under uncertain DA-market prices. The CSP will react by creating and communicating its DA-plan for the next day right before the DA-market closes, by optimizing its expected profits in the DA-market. In this study, we assume that the compensation for reducing the capacity of a connection of a CSP during some program time unit (PTU) is some fixed amount, but other compensation schemes based on e.g. the DA-market prices could also be considered.

B. Redispatch Contracts

If the CSP wants to participate in redispatch, it is obliged to send its DA-plan in the form of a distribution prognosis (D-prognosis) to the DSO before the closure of the DA-market. In this study, we assume that providing redispatch demands the CSP to only deviate from the D-prognosis unless redispatch is provided. In practice, the CSP can deviate from this schedule in real-time. The D-prognosis will thus function as a baseline for redispatch, defining the consumption/generation $p^{da}_{i',t}$ at a connection i' controlled by a CSP a at time step t. Given the D-prognoses and the DA-prices for the next day, the DSO can determine the expected congestion and can request upward/downward flexibility for some PTUs for the next day using the remaining part of the budget B. To prevent the DSO from directly buying/selling flexiblity, and to prevent the redispatch from causing system imbalances, the flexibility is not directly bought by the DSO, but traded in a national continuous intra-day market in the Netherlands. There, CSPs in the congested area place buy/sell orders as a reaction to the DSOs' request for flexibility, and the orders are matched by other market parties (MP) located outside the congested area [19]. If needed, the DSO pays the spread between the two orders from its available budget. This way, the national balance of supply/demand is not affected. In practice, the DSO can either contract parties to place redispatch bids, or MPs can submit bids freely. For this work, we focus on the former, redispatch contracts (RCs). These RCs can take various forms, but in this work, we assume that the contracts dictate for what price CSP a can place a buy/sell order in the market under the following conditions:

- For providing downward flexibility with connection i', the CSP a can submit a sell order in the redispatch market for $\pi^{csp,\downarrow}_{i',t}$, being the DA-price π^{da}_t plus a contracted premium π^{rc}_a specific to CSP a, in a pay-as-contract fashion. This entails that the CSP is willing to increase power production and sell the additional generated power, or will be willing to reduce power consumption and sell excess purchased power for the DA-price plus a bonus. Due to the premium π^{rc}_a, the CSP is thus incentivized to provide downward flexibility.
- For upward flexibility in the form of increased power consumption at connection i', it is assumed that the RC specifies that the CSP can submit a buy order in the redispatch market for $\pi^{csp,\uparrow}_{i',t}$, being equal to π^{DA}_t minus a discount π^{RC}_a. This entails that the CSP increases its power consumption and purchases additional consumed power for at most the favorable price $\pi^{DA}_t - \pi^{RC}_a$. Finally, for upward flexibility in the form of reduced power production, the RC specifies that the CSP limits its power production when it is absolved from costs, ensuring it does not lose any revenue while providing congestion services.

In this study, it is assumed that there is always a counter bid offered by a MP that completely clears the CSPs order at some intra-day price π^{id}_t. Although DSOs in the Netherlands are prohibited from power trading, they are willing to cover the so-called spread, the difference between buy and sell orders, when necessary to ensure the procurement of flexibility for congestion management. An example is that if the DSO requests downward flexibility when the intra-day price exceeds the CSPs sell order price, the MP will cover the sell price, resulting in 0 spread cost for the DSO. Conversely, if the intra-day price is lower than the CSPs sell order price, the spread costs for the downward flexibility for the DSO $\pi^{dso,\downarrow}_{i',t}$ will be the difference between the sell and buy orders $\pi^{da}_t + \pi^{rc}_a - \pi^{id}_t$. To visualize how this spread can vary in different scenarios, Fig. 2 provides an overview of the possible situations in the redispatch market and their corresponding DSO costs for downward flexibility $\pi^{dso,\downarrow}_{i',t}$, and upward flexibility $\pi^{dso,\uparrow}_{i',t}$, depending on the intra-day price. Note that depending on the prices in the DA- and ID market, and the premium/discount π^{rc}_a, redispatch can be cheap or expensive to a DSO. Also note that for the situation of reducing production, the price paid by the DSO is the full ID-price and thus relatively high. As a consequence, DSOs are incentivized to increase consumption, rather than curtailing production when requesting for upward flexibility. The costs for redispatch at connection i' for both the CSP a and DSO can thus be summarized by equations (1)-(4):

$$\pi^{csp,\downarrow}_{i',t} = -(\pi^{da}_t + \pi^{rc}_a) \tag{1}$$

$$\pi^{dso,\downarrow}_{i',t} = \max(0, \pi^{da}_t + \pi^{rc}_a - \pi^{id}_t) \tag{2}$$

$$\pi^{csp,\uparrow}_{i',t} = \begin{cases} (\pi^{da}_t - \pi^{rc}_a), & \text{if} \quad p^{da}_{i',t} \geq 0 \\ 0, & \text{if} \quad p^{da}_{i',t} < 0 \end{cases} \tag{3}$$

$$\pi^{dso,\uparrow}_{i',t} = \begin{cases} \max(0, \pi^{id}_t - \pi^{da}_t + \pi^{rc}_a), & \text{if} \quad p^{da}_{i',t} \geq 0 \\ 0, & \text{if} \quad p^{da}_{i',t} < 0 \end{cases} \tag{4}$$

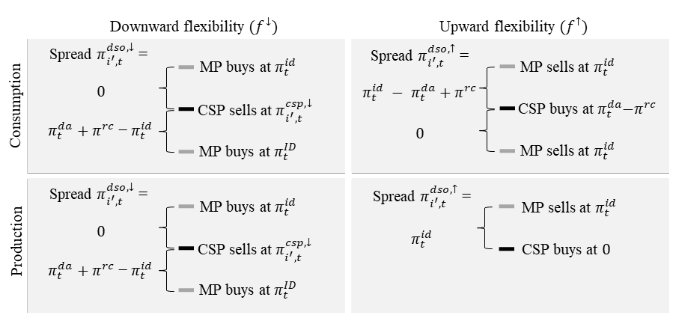


Fig. 2. Visual representation of the different downward and upward flexibility offers for consumption and production by the CSP, along with the corresponding DSO spread costs as a result of different intra-day price orders by the MP.

III. Model Formulation

In this work, we assume the DSO will apply the CRCs and RCs sequentially, resulting in two decision stages. In the first stage, the CRC activation is calculated according to a cost-effective minimization of the congestion under some fraction of the total budget allocated for the CRCs. We assume the DSO can anticipate the reaction of the CSPs to the CRC activation based on their optimization in the DA-market, like in a leader-follower game. The DA-market prices are considered to be uncertain at this stage. For the DA-price scenarios, we use multivariate t-distribution copulas [20], and reduce the scenarios using the fast-forward method from [21]. The results of the first stage are thus the CRC activation, the DA-schedules of the CSPs, and the remaining part of the budget. In the second stage, the DA-market prices and ID-market prices are known, and the CSPs provide their flexibility offers in the redispatch market. The DSO then selects the bids that minimize the congestion most cost-effectively while spending no more than the remaining part of the budget. This framework is also illustrated in Fig. 1. We assume that the CSPs in our network can only control electric vehicles (EV) and solar cells (PV), but the model can easily extended to other assets if a convex set of constraints is provided. The model formulations for the two stages are now discussed in more detail below.

A. Stage 1: CRC activation and DA-schedule communication

For the first stage, we adopt the following stochastic bi-level mixed-integer SOCP:

$$\min_{\Xi_{DSO_1}} \pi^+ \sum_{ij,t} S^{sqr,+}_{ij,t} + \sum_{a,i'\in\Omega^a_B,t} \Pi^{crc}_a z^{crc}_{i',t} \quad (5)$$

$$\sum_{a,i'\in\Omega_{CSP_a},t} \Pi^{crc}_a z^{crc}_{i',t} \leq \theta^{crc} B \quad (6)$$

$$S^{sqr,+}_{ij,t} \geq 0 \qquad \forall ij,t, \quad (7)$$

$$S^{sqr,+}_{ij,t} \geq P^2_{ij,t} + Q^2_{ij,t} - \overline{S}^2_{ij} \qquad \forall ij,t, \quad (8)$$

$$\sum_{ki} P_{ki,t} - \sum_{ij} P_{ij,t} = p_{i,t} \qquad \forall i,t, \quad (9)$$

$$\sum_{ki} Q_{ki,t} - \sum_{ij} Q_{ij,t} = q_{i,t} \qquad \forall i,t, \quad (10)$$

$$V^{sqr}_{i,t} - 2(R_{ij}P_{ij,t} + X_{ij}Q_{ij,t}) = V^{sqr}_{j,t} \qquad \forall i,t, \quad (11)$$

$$\begin{aligned} q_{i,t} = {} & p^{bl}_{i,t} \tan(\arccos(\mathrm{pf}^{bl})) \\ & + \sum_{e:e=i'} p^{ev}_{e,t} \tan(\arccos(\mathrm{pf}^{ev})) \\ & - \sum_{p:p=i'} p^{pv}_{p,t} \tan(\arccos(\mathrm{pf}^{pv})) \qquad \forall i,t, \quad (12) \end{aligned}$$

$$\underline{V}^2 \leq V^{sqr}_{i,t} \leq \overline{V}^2 \qquad \forall i,t, \quad (13)$$

$$z^{crc}_{i',t} \in \{0,1\} \qquad \forall i',t. \quad (14)$$

Where for all CSPs indexed by a:

$$p_{i',t}, p^{ev}_{e,t}, p^{pv}_{p,t} \in \quad (15)$$

$$\begin{cases} \min_{\Xi_{CSP}} \sum_{i'\in\Omega_a,t,\omega} \phi_\omega \pi^{da}_{t,\omega} p^{da}_{i',t} \Delta t & (16) \\ \overline{p}_{i',t} = z^{crc}_{i',t}\overline{p}^{crc}_{i',t} + (1 - z^{crc}_{i',t})\overline{p}^{ph}_{i',t} \quad \forall i',t & (17) \\ -\overline{p}_{i',t} \leq p_{i',t} \leq \overline{p}_{i',t} \quad \forall i',t & (18) \\ 0 \leq p^{pv}_{p,t} \leq \overline{p}^{pv}_{p,t} \quad \forall p,t & (19) \\ 0 \leq p^{ev}_{e,t} \leq a_{e,t}\overline{p}^{ev}_{e,t} \quad \forall e,t & (20) \\ SOC^0_e + \sum_{\tau\leq t} p^{ev}_{e,\tau}\Delta t \leq \overline{SOC}_e \quad \forall e,t & (21) \\ SOC^0_e + \sum_{\tau\leq t^{dep}_e} p^{ev}_{e,\tau}\Delta t \geq SOC^{dep}_e \quad \forall e & (22) \\ p_{i',t} = p^{bl}_{i',t} + \sum_{e:e=i'} p^{ev}_{e,t} - \sum_{p:p=i'} p^{pv}_{p,t} \quad \forall i',t & (23) \end{cases}$$

Here, the DSO optimizes over the decision variables $\Xi_{DSO_1} = \{P_{ij,t}, Q_{ij,t}, V^{sqr}_{i,t}, S^{sqr,+}_{ij,t}, z^{crc}_{i',t}\}$ of which $P_{ij,t}$ and $Q_{ij,t}$ denote the active and reactive power flow through the branch (cable or transformer) $ij \in \Omega_L$ between buses $i,j \in \Omega_B$ at time step in the next day $t \in \Omega_T$ (15-minute resolution). Then follows the voltage magnitude squared $V^{sqr}_{i,t}$ at the buses/time steps. The superscript sqr is adopted to illustrate that the voltage magnitude squared and not the voltage magnitude is considered to be the decision variable. Similarly, $S^{sqr,+}_{ij,t}$ denotes the squared overloading in the branches, while $z^{crc}_{i',t}$ is the binary activation variable of the CRC contract at some bus $i' \in \Omega_a \subset \Omega_B$ controlled by a CSP a. The associated costs of doing so for a time step is denoted by Π^{crc}_a. The objective function of the DSO (5) minimizes the systems overloading first, and the CRC activation cost second. This is achieved by scaling the overloading term by large constant congestion cost $\pi^+ = 100.0\mathrm{Eur/kVA}^2$. This way, even a small overloading of 1.0kVA costs more than the total congestion management budget B available. In contrast to some other works, which take actual transformer overloading costs into account [6], we thus focus on maximum congestion prevention with the given budget.

Equations (6) limits the DSO from spending more than a fraction θ^{crc} of its budget on CRC contracts. Equations (7)-(8) define the overloading $S^{sqr,+}_{ij,t}$, while equations (9)-(11) are the linear Distflow equations. Equation (12) presents the reactive power production/consumption at every node in terms of EV, PV, and a baseload in terms of their power factors pf. Equation (13) presents the voltage constraints and (14) the integrality constraints for the CRC activation.

In the second layer, the CSPs decide on their active power consumption/production at their buses, the amount of power charged by their by EVs, and the amount of non-curtailed PV power: $\Xi_{CSP} = \{p_{i',t}, p^{ev}_{e,t}, p^{pv}_{p,t}\}$ with $e \in \Omega_{EV}$ the set of buses with an EV and $p \in \Omega_{PV}$ the set of buses with a PV. The CSP minimizes its costs from the DA-market in (16) weighing possible DA-price scenarios $\pi_{t,\omega}$ indexed by the scenario number $\omega \in \Omega_{DA}$ with a probability ϕ_ω. The parameter Δt denotes the time step size of the model, which is taken to be 15 minutes in this work. Equations (17)-(18) show how the CRC activation limits the capacity of a contracted connection from its physical capacity $\overline{p}_{i',t}^{ph}$ to its contracted capacity $\overline{p}_{i',t}^{crc}$. Then follow a couple of asset constraints for PV (19) and for EV (20)-(22). The first of the EV constraints limits charging power to its maximum charging power if the car is able to charge ($a_{e,t} = 1$) and to 0 otherwise. The other two constraints prevent the CSPs from overcharging the EV and forces the car to leave at a desired state of charge SOC_e^{dep} at time of departure t_e^{dep}. The last equation (23) is the balance for active power consumption/production in terms of the assets and the baseloads. Since the lower-level problem is convex, and Slater's conditions holds in our case-study presented later, we can cast the bi-level problem into an equivalent single-level problem by applying the KKT-conditions on the lower CSP subproblems [22]. Only the stationarity conditions will be presented in more detail, as we adopt the standard big-M method to linearize the complementarity constraints with a value of $M = 10^7$. The stationarity conditions are given by:

$$\sum_{\omega} \phi_\omega \pi_{t,\omega}^{da} \Delta t + \mu_{i',t}^{ub} - \mu_{i',t}^{lb} - \lambda_{i',t} = 0 : p_{i',t} \;\; \forall i', t \tag{24}$$

$$\mu_{p,t}^{pv,ub} - \mu_{p,t}^{pv,mi} - \lambda_{p,t} = 0 : p_{p,t}^{pv} \;\; \forall p, t \tag{25}$$

$$\begin{aligned} \mu_{e,t}^{ev,ub} - \mu_{e,t}^{ev,lb} + \lambda_{e,t} - \mu_e^{soc,dep} \Delta t \\ + \sum_{\tau \geq t} \mu_{e,\tau}^{soc,ub} \Delta t = 0 \qquad &: p_{e,t}^{ev} \;\; \forall e, t, \end{aligned} \tag{26}$$

where $(\mu_{i',t}^{lb}, \mu_{i',t}^{ub})$, $(\mu_{p,t}^{pv,lb}, \mu_{p,t}^{pv,ub})$, $(\mu_{e,t}^{ev,lb}, \mu_{e,t}^{ev,ub})$ are the non-negative dual variables of constraints (18)-(20) respectively, where $\mu_{e,t}^{soc,ub}$ and $\mu_{e,t}^{soc,dep}$ are the non-negative dual variables of constraints (21)-(22) respectively, and where $\lambda_{i',t}$ is the dual variable corresponding to the equality constraint (23). The equations (5)-(23), (24)-(26), dual feasibility constraints, and the linearized complementary slackness constraints form a quadratic mixed-integer second-order conic program. This problem can for smaller instances be solved using Gurobi [23] with a minimal gap of 0.1% on an Intel(R) Core(TM) i7-9750H CPU processor in a couple of minutes. The output for this model is the optimal CRC activation $z_{i',t}^{crc,*}$, the DA-schedules for the CSPs $p_{i'.t}^{da} := p_{i'.t}^{*}$, and the remaining budget for dispatch B'. Note that this budget can be larger than $(1 - \theta^{crc})B$ as the full CRC budget might not have been required, or no further congestion could be prevented using CRCs.

B. Stage 2: Redispatch

For redispatch, we assume the DSO procures the required redispatch flexiblity for the lowest cost via the redispatch market, being constrained by the redispatch budget B'. Both the DA-market prices and ID-market prices have now realized, so the cost/benefits for the DSO and CSPs are now known. We repeat that for a CSP it is always profitable to provide downward flexibility at some connection $f_{i',t}^{\downarrow}$, while it gains/loses nothing to provide upward flexibility $f_{i',t}^{\uparrow}$ while feeding in. Only when consuming, it costs the CSPs money to provide downward flexibility. We will assume that a CSP a is willing to provide this upward flexibility if the price it needs to pay $\pi_t^{da} - \pi_a^{rc}$ is smaller than the average DA-price that day $\langle \pi_t^{da} \rangle$. With this assumption, the redispatch market clearing can be cast into the following problem:

$$\min_{\Xi_{DSO_2}} \pi^+ \sum_{ij,t} S_{ij,t}^{sqr,+} + \sum_{a,i' \in \Omega_a,t} (\pi_{i',t}^{dso,\uparrow} f_{i',t}^{\uparrow} + \pi_{i',t}^{dso,\downarrow} f_{i',t}^{\downarrow}) \Delta t \tag{27}$$

$$\sum_{a,i' \in \Omega_a,t} (\pi_{i',t}^{dso,\uparrow} f_{i',t}^{\uparrow} + \pi_{i',t}^{dso,\downarrow} f_{i',t}^{\downarrow}) \Delta t \leq B' \tag{28}$$

$$0 \leq f_{i',t}^{\uparrow} \leq \overline{p}_{i',t}^{ph} - p_{i',t}^{da} \qquad \forall i', t, \tag{29}$$

$$0 \leq f_{i',t}^{\downarrow} \leq \overline{p}_{i',t}^{ph} + p_{i',t}^{da} \qquad \forall i', t, \tag{30}$$

$$f_{i',t}^{\uparrow} = 0 \qquad \forall i', t : \pi_{a,t}^{csp,\uparrow} > \langle \pi_t^{DA} \rangle \tag{31}$$

$$p_{i',t} = p_{i',t}^{da} + f_{i',t}^{\uparrow} - f_{i',t}^{\downarrow} \quad \forall i', t \tag{32}$$

$$(7) - (13), (19) - (23)$$

The set decision variables for the DSO in the second stage now given by: $\Xi_{DSO_2} = \{P_{ij,t}, Q_{ij,t}, V_{i,t}^{sqr}, S_{ij,t}^{sqr,+}, f_{i',t}^{\uparrow}, f_{i',t}^{\downarrow} p_{i',t}, p_{p,t}^{pv}, p_{e,t}^{ev}\}$. The objective function (27) again minimizes the component overloading first and the redispatch costs second. Equation (28) denotes the budget constraints, (29)-(30) limit the provided flexibility up/down to the physical connection capacity, and (31) presents the willingness to buy constraint from the CSPs. Lastly, equation (32) is the redispatch constraint. The prices $\pi_{i',t}^{dso,\uparrow}, \pi_{i',t}^{dso,\downarrow}, \pi_{i',t}^{csp,\uparrow}, \pi_{i',t}^{csp,\downarrow}$ are given by equations (1)-(4) in section II-B. The problem is again solved using Gurobi with a minimal gap of 0.1% [23]

IV. Results

In this results section, we consider a case study of a congested Dutch low-voltage network with a high penetration of PVs (13 in total) and EVs (also 13 in total). The network is presented in Fig. 3 and it consists of 25 connections, 53 buses, 53 cables, and a 100kVA transformer, connecting the network to the medium-voltage grid. There are two CSPs active in this congested region. Nine out of the 25 connections are contracted by CSP 1, while eight are contracted by CSP 2. Connected to these contracted connections are either: 1) only a baseload, 2) a baseload + PV, 3) a baseload + EV, or 4) a baseload + PV + EV. The connections not contracted by one of the CSPs only have a baseload. The quarter-hourly baseload profiles are based on anonymized smart-meter data, and the PV profiles are based on an annual hourly solar irradiance and temperature data set from the Royal Dutch Meteorological Institute (KNMI), interpolated to a 15-minute resolution [24]. The EV charging sessions are synthetically generated using the approach from [25]. Given the 100kVA capacity of the grid, there is a budget of €2.44 available for congestion management in this area. We will assume that both CSP 1 and CSP 2 are contracted with a CRC and a RC. The contract parameters for the two CSPs are presented in Table I. Note that CSP 1 is cheaper in terms of activating its CRC, while and CSP 2 is cheaper in terms of its RC premium/discount.

TABLE I
CONTRACTED PARAMETERS

Parameter	CSP 1	CSP 2
Π^{crc}[€]	0.15	0.2
$\overline{p}^{crc}$[kW]	4.0	4.0
π^{rc}[€/kWh]	0.02	0.01

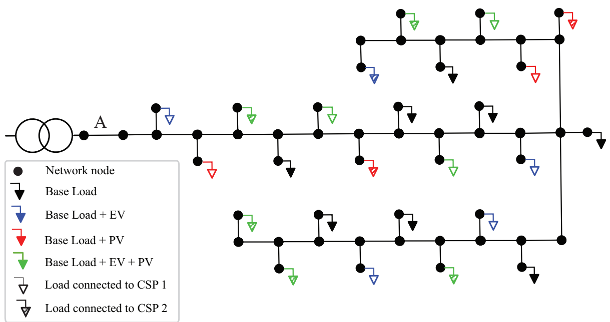


Fig. 3. Schematic overview of the congested low-voltage network considered in the case study. The main cable connecting the network to the transformer is indicated with A.

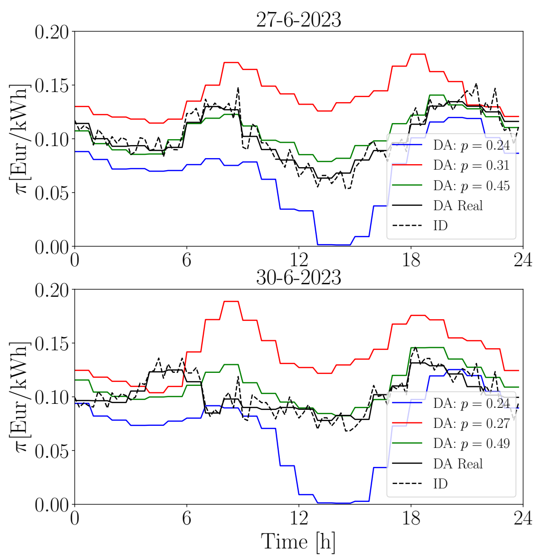


Fig. 4. The day-ahead price scenarios and their probabilities (in blue, red, and green), real day-ahead prices in the Netherlands, and the synthetic intra-day prices for which a market party will bid into the redispatch market for two days in June 2023.

We will consider 2 market situations, presented in Fig. 4. The figure presents both the reduced scenarios for the DA-prices that the CSPs will consider in its DA-scheduling, and the realized DA- and ID- prices that day. For the DA-prices this is the real price for the Netherlands that day, while the ID-price is modeled as that DA-price plus a Gaussian noise with mean 0.0 and a standard deviation of 0.01€/kWh. A more detailed account of the relation between the DA-prices and prices offered in the intraday market in the Netherlands will be a topic for future work. The typical value for the real DA-prices is 0.10 €/kWh, and the redispatch incentives from Table I are thus about 20% and 10% of the DA-prices for CSP 1 and CSP 2 respectively. We observe that the copula-based scenarios capture the main characteristics of the real DA-prices well. For what follows, it is important to note here that on the 27th of June both the DA-price and ID-price are more volatile over the day, resulting in relatively low prices during the afternoon, and relatively high prices during the evening.

Fig. 5 shows for this case study the relative cable loading on the main cable from the transformer over the 30th of June after the application of the two bilateral contract types. For this plot, we considered the situation where up to half of the budget could be spent on CRC-activation (that is, $\theta^{crc} = 0.5$). We clearly observe that the cable would have been overloaded if no flexibility was procured via the contracts. The overloading would have taken place both during the afternoon due to PV generation, but also during the evening due the the arrival and charging of the EVs. In total, €1.20 was spent on CRCs, all procured from the cheaper CSP 1. The CRCs are used to reduce the overloading due to the EVs, and to reduce part of the overloading from the PV generation during the afternoon. Afterward, €1.10 was spent on upward flexibility, approximately equally distributed over the two CSPs, to reduce the remaining overloading during the afternoon. Both CSPs were procured more or less equally, as the upward flexibility costs for the DSO are the same (the ID-price) for both CSPs during hours of generation.

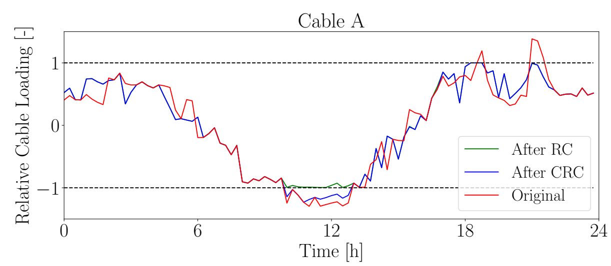
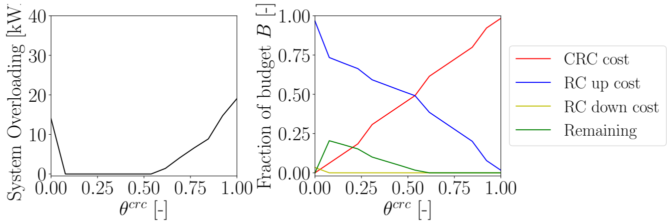
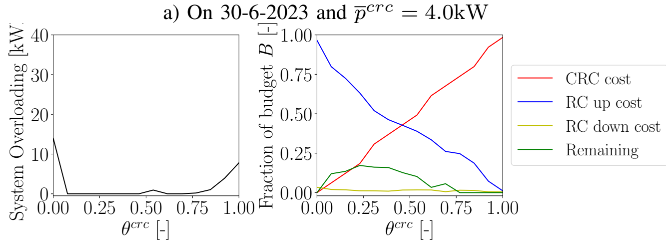


Fig. 5. The relative cable loading of cable A before flexibility is procured; after the capacity restriction contracts are activated; and after the redispatch contracts are activated too. The simulated date is 30-6-2023 and up to half of the total budget could be spent on the capacity restriction contracts.

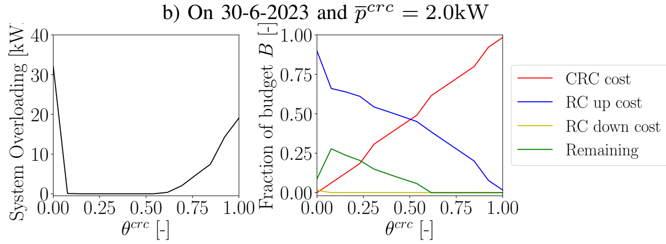
The results are however strongly dependent on the fraction of budget spent on CRCs, θ^{crc}. Fig. 6 presents left the total system overloading and right the DSOs spending of the budget on the contracts as a function of θ^{crc} under several conditions. In Fig. 6a), the situation is as discussed before, so the values at $\theta^{crc} = 0.5$ correspond to the cable loading presented in Fig. 5. We observe that for very low values of $\theta^{crc} < 0.1$ and high values $\theta^{crc} > 0.6$, congestion occurs. For low CRC budgets, the CRCs cannot be utilized and it is too expensive to resolve the component overloadings with redispatch alone. This is because it is relatively expensive to apply redispatch to a connection with a lot of consumption/production compared to applying a CRC, as the redispatch costs are volume dependent. Conversely, when CRC budgets are high, a significant portion of the budget is allocated to CRCs. In this situation, there persists a problem of component overloading in the afternoon, as multiple connections generate power at the contracted capacity of 4.0kW, still leading to cable overloading. The remaining budget for redispatch is not high enough to resolve this issue. If we look at the costs, the remaining budget peaks



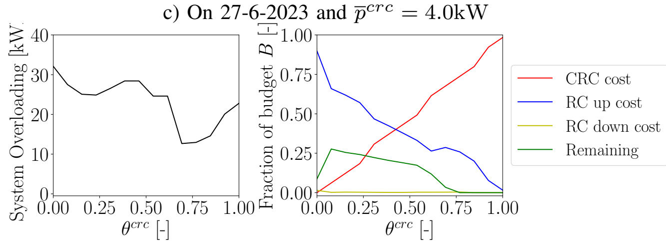
a) On 30-6-2023 and $\overline{p}^{crc} = 4.0$kW



b) On 30-6-2023 and $\overline{p}^{crc} = 2.0$kW



c) On 27-6-2023 and $\overline{p}^{crc} = 4.0$kW



d) On 27-6-2023 and $\overline{p}^{crc} = 2.0$kW

Fig. 6. The total system overloading and fractions of the budget of 2.44€ spent/remaining over the capacity restriction contracts (CRCs) and the redispatch contracts (RCs) for various allocations of the budget on capacity restriction contracts θ^{crc}. The plots are made for 2 days, and 2 contracted capacities in the CRCs.

around $\theta^{crc} \approx 0.1$. Given that for this budget allocation the system overloading is 0 as well, it seems to be the optimal budget allocation. This case thus shows that combining the two instruments is cost-effective. If we now decrease the contracted capacity for both CSPs from 4.0kW to 2.0kW, we make applying CRCs more effective, as more flexibility can be procured for the same costs. We thus observe in Fig. 6b) that allocating $\theta^{crc} = 0.25$ to CRC is the most cost-effective approach to reduce all overloading in the system. We also observe that for high CRC budget allocation more system overloading can be prevented. However, applying low contracted capacities can be risky as well, as is demonstrated in Fig. 6d). There we consider the day 27-6-2023 and we observe that under no budget allocation over the two contracts, the total system overloading can be reduced to 0. The leftover overloading is now at the evening peak caused by the EVs. The CRCs reduced the EV charging as much as possible already due to the low contracted capacity, resulting in non-zero charging at the PTUs the CRCs are not active. To reduce the overloading further, downward flexibility should be accompanied by upward flexibility during other PTUs to get the EV cars full when departing. However, because the market prices are relatively high compared to the mean market prices on the 27th of June during charging hours, no CSP is willing to pay the price to provide upward flexibility under the current set of incentives. As a result, there is overloading still, even though there is a budget to spend. For higher values of the contracted CRC capacities of 4.0kW, demonstrated in Fig. 6c), this problem is not there, and the plots are very similar to the ones from Fig. 6a) on the 30th of June. This example illustrates that without proper consideration of the contracted parameters, the ability of the DSO to provide congestion management can strongly depend on the national market conditions, which can be undesired.

V. Conclusion

This paper provides the first formalization of the capacity restriction contracts (CRCs) and redispatch contracts (RCs) recently introduced in the Netherlands for congestion management in distribution networks. It additionally offers an optimization model to address the distribution service operator's (DSO) decision-making process regarding the allocation of a given budget between these contract types, aiming for cost-effective congestion management. In this model, the CRCs and RCs are activated sequentially, combining a mixed-integer SOCP problem with a continuous SOCP. The CRC activation is formulated as a bi-level leader-follower game between the DSO and the congestion service provider (CSP), while the redispatch problem is single-level.

The framework can be used to study the optimal budget allocation over the CRCs and RCs and its sensitivity to contracted parameters and market conditions. This was demonstrated in a case study, involving a typical Dutch low-voltage network with a high penetration of PV and EV controlled by two active CSPs. It was shown that using a mix of the two instruments is typically the most cost-effective. Moreover, it illustrates that, under appropriate contract parameters, the budget stipulated by grid codes for congestion management in this network can be adequate. Nevertheless, the study also highlights that improper tuning of contracted parameters may lead to insufficient procurement of flexibility in scenarios with high market prices during overloading, due to the strong dependency of the DSO's redispatch costs on the national day-ahead and intra-day market prices.

The authors acknowledge that the sequential activation of contract types without coordination might not be the most optimal strategy. This initial sequential formulation provides valuable insights, serving as a foundation for the coordinated budget-constrained activation of CRCs and RCs, which will be the focus of future research. These future endeavors aim to refine the approach towards coordinated, budget-constrained activation of CRCs and RCs, thereby further enhancing the efficiency and effectiveness of congestion management strategies in distribution networks.

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