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Flexibility for congestion management: A demonstration of a multi-mechanism approach

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***Abstract*—Distribution system operators are investigating new methods to manage network congestion and avoid overloading. Among these methods is the application of flexibility. This paper will present a field implementation as part of the H2020 Interflex project. Two parallel mechanisms will be implemented: a local flexibility market and a variable connection capacity. Multiple aggregators will participate on the local flexibility market, trading flexibility day-ahead and intraday. The DSO can compete for flexibility with other interested parties. In parallel, the concept of variable connection capacity is implemented. The variable connection capacity is based on a contractual agreement between distribution system operator and a customer's point of connection. The connection capacity is set at two levels: off- and on-peak. The scenarios include medium to low voltage transformers and low voltage feeders. In the paper, various test-scenarios are described, and an outlook of the field experiments is provided.**

***Index Terms*—Congestion Management, Demand Response, Energy Markets, Flexibility, Smart Grids.**

I. Introduction

The electricity system is shifting towards a more sustainable system. As a result, increasing amounts of distributed energy resources such as solar photo voltaic (PV), electric vehicles (EV), batteries, and heat pumps are connected to the distribution network. The electrification of heating demand and mobility increases the peak load, while large-scale PV integration causes bidirectional power flows in the distribution network. This may introduce new peak loads.

The changing loading of the distribution network poses various operational challenges, among which network congestion (i.e. network overloading). Traditionally, distribution system operators (DSOs) reinforce their networks to prevent and mitigate congestion. In order to save costs of grid reinforcements, alternative solutions are being investigated. One of these solutions is the application of flexibility.

This paper focuses on the application of flexibility for congestion management. We define congestion as a network overloading. The work presented elaborates on a field implementation of a multi-mechanism solution. Two mechanisms will be implemented in parallel, a local flexibility market with multiple aggregators, and a variable connection capacity. The concepts of both mechanisms will be explained. Then, a large-scale field implementation applying both mechanisms is introduced. The field implementation is part of the Dutch demonstrator of the H2020 Interflex project [1], where PV, a central battery and EV charge points (EVCPs) provide the local flexibility. The field implementation will be used to evaluate and compare both mechanisms, from a DSO perspective.

Section II will briefly explain various mechanisms for unlocking flexibility for congestion management. After this, section III and IV elaborate on respectively the local flexibility market, and the variable connection capacity. Section V describes the setup of the field implementation, including the goals and tested scenarios. Finally, section VI concludes this paper.

II. Flexibility for congestion management

A. Definition of flexibility

Flexibility can be defined in various ways, and therefore defining flexibility throughout this paper is necessary. Since the paper focuses on congestion management, the relevant parameters of flexibility can be limited to location, period, time, and amount of power adjustment. Therefore, for this paper the definition from [2] is used, defining flexibility as *"a power adjustment with a specific size and direction, sustained at a given moment for a given duration from a specific location within the network"*.

B. Flexibility mechanisms and sources

Various flexibility mechanisms for congestion management are described in literature. The research area of demand response (DR), both implicit and explicit, has addressed congestion management mechanisms. The definitions of implicit and explicit DR by [3] are loosely followed. Implicit (or price based) DR is defined as the possibility of users to respond

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to price signals that reflect network and market variability. Explicit (or incentive based) DR is defined as a commitment of demand-side flexibility, traded on one or more energy markets.

Research in the field of implicit DR relates to new and/or adjusted tariff structures, such as capacity payments, time of use, and critical peak pricing. In the pilot project Jouw Energie Moment (Your Energy Moment) in the Netherlands for example, changes in household energy consumption as a result of a price signal have been analyzed [4].

Another strategy to unlock flexibility is the application of direct control, where a connection or an appliance behind the meter is influenced directly. Various countries apply direct control already for decades on for example residential water boilers [5]. More recent studies also demonstrate direct control. An example is the case of NiceGrid, where direct control is used for peak load reductions, by reducing the electricity consumption of residential heaters without compromising any comfort level of residents [6].

The availability of flexibility sources remains a prerequisite to applying any of these flex mechanisms. Various appliances have been evaluated as flexibility source in both academic and pilot settings [4] [7] [8]. Among these (but not limited to) are batteries (both home batteries and large-scale centralized batteries), EV, solar PV, heat pumps, and household appliances.

Two mechanisms will be addressed in more detail, namely a flexibility market (section III) and variable connection capacity (section IV). These are the mechanisms applied in the field implementation.

III. Flexibility market

A. Description

A (local) flexibility market can provide a marketplace through which a DSO can obtain flexibility for congestion management. This market can coexist with traditional energy markets, such as the ancillary service market, and the day-ahead and intraday wholesale markets. Aggregators of flexibility now have an additional opportunity to trade flexibility, while DSOs have to compete with already existing markets.

Flexibility markets can cover different time horizons. Flexibility can be traded ahead in time, for example in a day-ahead market. Alternatively, flexibility can be traded near real-time in an intraday market. Different types of products can be traded, for example long-term contracts and an open market.

In long-term contracts, DSOs can agree on a price for a guaranteed quantity of flexibility. The aggregator keeps flexibility in reserve, and based on a signal this flexibility is enabled. Payment can be done either capacity based, or a combination of capacity based and shifted energy based.

An open market can provide an alternative. In such a market, the price of flexibility is not set ahead of time. Aggregators are free to sell flexibility to the highest bidder. Payments in such markets are based on shifted energy. In such markets, DSOs risk not obtaining the needed flexibility, or paying a high price to secure the necessary amount.

Besides the time horizon, and type of product, flexibility markets can differentiate between a centralized and local market structure. A centralized market has the potential advantage that the market is accessible for a broad group of parties, similar to the wholesale markets. This can enable equality and ensure similar market rules within an area (for example, a national flexibility market).

Implementing a local flexibility market on the other hand involves less parties. This is likely to reduce the implementation time, as an agreement on the market structure and rules depends on relatively few parties. Flexibility markets are an upcoming phenomena, thus the ideal market structure is yet unknown. Since a congestion problem is a local phenomenon, this work assumes a local market for the field implementation.

Research in the field of flexibility markets is no longer limited to academia; industry takes an interest also. A number of industrial partners collaborated in the development of a non-profit standard: the Universal Smart Energy Framework (USEF). USEF provides a standard to develop flexibility products and services, stacked on top of the already existing energy markets [9].

B. Proposed market definition

To enable all market parties to participate equally on the flexibility and energy markets, the implementation of a flexibility market for DSOs without obligatory participation (an open market) is proposed. Aggregators have the opportunity to offer flexibility to the DSO, through a single-buyer flexibility market. However, aggregators can optimize their offerings, by enabling them to bypass the flexibility market and trade on other markets (e.g. wholesale markets, ancillary service market, portfolio optimization).

Within the field implementation, the flexibility market for congestion management is setup in two stages. During the first stage, a day-ahead market is implemented. In this day-ahead market, flexibility can be requested per program time unit (PTU). The PTU in the field implementation is set to blocks of fifteen minutes. The gate closure time of the day-ahead flexibility market is aligned with the wholesale day-ahead market. To prevent the possibility of infinite negotiations before gate closure, a single-cycle mechanism is proposed.

During the second stage of the field implementation, an intraday component is added to the flexibility market. From this point forth, the DSO can correct the (day-ahead) expected need for flexibility throughout the day, during which the need for flexibility is evaluated during every PTU. Once again, the gate closure time is aligned with the wholesale market.

C. Relation to other research

Two similar projects (Energiekoplopers, Heerhugowaard, and Lombok, Utrecht) have been demonstrated in the Netherlands recently. Both use USEF as a basis for their markets, and use flexibility to manage congestion.

In the pilot in Heerhugowaard, both a day-ahead and an intraday flexibility market are introduced. The intraday market is however limited to one cycle, rather than a continuous market throughout the day [7]. Furthermore, the (single) aggregator and balance responsible party are implemented by the same actor, giving a single actor multiple roles [10]. The Utrecht pilot implements only a day-ahead market, with a single aggregator [8].

During the demonstration in Eindhoven, it is proposed to implement a market with split-roles (i.e. a different actor for every role), and with multiple aggregators. Furthermore, the proposed intraday market has multiple decision moments (i.e. every PTU). Another addition to existing research is the combination of a flexibility market with another flexibility mechanism (i.e. variable connection capacity).

IV. Variable connection capacity

A. Description

The variable capacity on the point of connection (PoC) aims at relieving the distribution network during the period of expected peak loading. This is done by changing from a flat capacity profile to a variable capacity profile, where capacity becomes time-dependent. The DSO enforces this based on a contractual agreement, and verifies compliance with measurement data.

Four parameters can be distinguished, namely the maximal off- and on-peak capacity, the time of starting the capacity reduction, and the period of capacity reduction (e.g. number of hours). Fig. 1 illustrates the concept.

The concept of variable capacity can be implemented in various ways, two of which are a fixed capacity profile on the PoC per day, and a dynamic profile on the PoC per day. With a fixed profile per day, the period of capacity reduction and the time of the start of capacity reduction are set at a fixed moment of the day (for example the hours of the daily peak load). An advantage of such fixed capacity profile is not needing a communication interface. A contractual agreement between DSO and connected party, specifying the capacity reduction for each day, will suffice. A possible disadvantage is the lack of control. Peak loads might not always occur at the same moment in time, in which case a fixed capacity profile will no longer suffice.

That leads to the alternative with a dynamic profile per day, in which the starting time of the capacity reduction is determined on a daily basis, and is communicated ahead of time (e.g. day-ahead). The starting time is then matched with the expected peak load of the network, resulting in an advantage for the dynamic profile over the fixed profile per day. As a consequence, information about this starting time needs to be communicated with the PoC on a predetermined moment in time, resulting in additional infrastructure.

For the dynamic capacity profile, the period of capacity reduction could also be made dynamic, up to a prearranged maximum per day. Connections to the power system should however be non-discriminatory, and such variable period might compromise the non-discriminatory requirement.

This non-discriminatory requirement could on the other hand be guaranteed with a variable period of capacity reduction, by adding an extra parameter: the cumulative time of capacity reduction per period (e.g. day, month or year). In such a situation, the DSO reduces the capacity for a predetermined time per, for example, year. The moments and duration at which this reduction occurs throughout the year, is however flexible. This way, a DSO can use the variable connection capacity on exactly those moments the network has most congestion, which is advantageous.

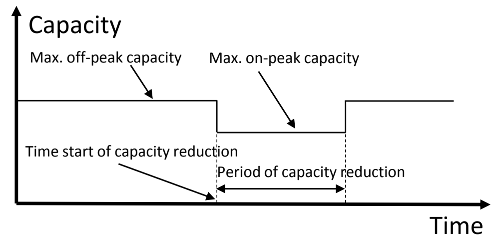

Fig. 1. Visualization of variable connection capacity over time.

The decision to reduce the connection capacity for a certain time and period however, becomes more complicated. An example. Assume a congestion problem is expected in the beginning of a year: a DSO now has to decide whether to use an amount of the allowed cumulative reduction time, or to save it for a potential higher need later in the year. Furthermore, to remain non-discriminatory, a DSO also has to ensure the contracted reductions have been all been executed, without coming short of, or exceeding this agreement. This complexity is a disadvantaged in comparison to a dynamic profile per day, where the complexity of a decision is smaller.

B. Proposed implementation

For the proposed field implementation, two stages can be distinguished for the variable connection capacity. Initially, a fixed variable connection capacity profile will be set. In this case, the on-peak capacity is set between 17:00 and 20:00 (the traditional hours of peak load in residential areas [11]). In stage two, a dynamic variable capacity profile is set. In order to run this mechanism parallel with the flexibility market, the on-peak time slot is communicated day-ahead, before gate-closure of the (day-ahead) flexibility market (e.g. at 8:00). The period of capacity reduction is fixed as a block of three hours per day.

V. Field implementation

A. Interflex project

In the Horizon2020 project Interflex, twenty European partners collaborate on four topics: demand response, energy storage, distribution automation, and large-scale integration of EV. This is done in six demonstrators [1]. One of the demonstrators is in the Dutch district of Strijp-S, Eindhoven.

On the demonstration site on Strijp-S, the large-scale application of flexibility for distribution grid management is evaluated. The goal is to test an integral solution, where two flexibility mechanisms are combined. Both a local flexibility market and a variable connection capacity are implemented in parallel, and will be evaluated and compared.

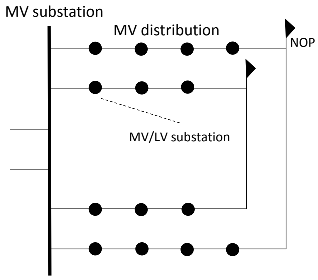

Fig. 2. Visualization of MV distribution rings, with normally open points.

B. Local flexibility and inflexible loads

The local flexibility consist of a large-scale PV system (268kWp), a smart storage unit (SSU, central battery) of 255kVA/315kWh, and 26 electric vehicle charge points (EVCPs, 22kW each). The inflexible load is represented by 354 apartments, a parking garage, and a number of small-medium enterprises (SMEs).

C. Network topology

The MV distribution network in the Netherlands is typically designed ring shaped, connecting various MV/LV substations. A normally open point (NOP) is added to each MV ring. Consequently, the MV network is operated radially [11]. Fig. 2 illustrates a typical MV topology in a schematic overview.

The demonstration site is fed by an MV ring, operated as two radial feeders with a normally open point. This MV feeder is connecting eight MV/LV substations. The loads are connected to the last two successive MV/LV substations of the feeder. Each substation has eight outgoing (LV) feeders, and is equipped with a 630kVA transformer.

Substation 1 connects 198 apartments (two buildings), spread over four LV feeders. Furthermore, the SMEs on the first floor, and the shared facilities of the apartment buildings (e.g. elevators, lighting) are connected to a separate LV feeder. Three feeders are connected to the parking garage, to which the PV installation and 14 charging stations are connected. A schematic overview of the substation is provided in Fig. 3.

Substation 2 connects 152 apartments (one building), spread over four LV feeders. A separate feeder is used to connect the shared facilities. Furthermore, a feeder is used to connect 12 EVCPs. The seventh feeder connects the SSU to the distribution network, while the last feeder is empty. A schematic overview of the substation is provided in Fig. 4.

D. Congestion points

Dutch DSOs dimension their distribution networks based on a coincidence factor. For the area of Strijp-S, the average peak load per household on a transformer level is 1.4kW, excluding load growth over the lifetime of the distribution network. Household peak loading in the Netherlands is based on an evening peak, typically between 17:00 and 20:00 [11]. Arrival times and charge rates vary per EV. Therefore, EVCPs are also exposed to a coincidence factor. This coincidence factor is assumed to be 50%. Due to the physical placement of the EVCP, a peak in the afternoon and/or early evening can be expected.

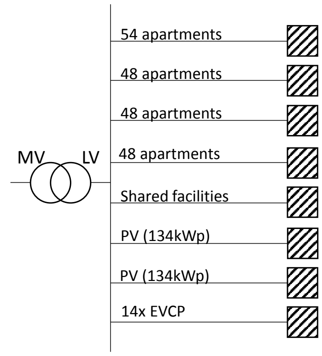

Fig. 3. Schematic overview loads substation 1.

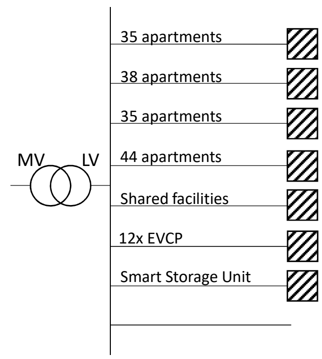

Fig. 4. Schematic overview loads substation 2.

Four congestion points can be distinguished, two MV/LV transformers (substation 1 & 2), and two LV feeders (outgoing EVCP's feeders). The rated power of both transformers is 630kVA, the current rating of the feeders is 3x250A (approximately 173kVA). Table I illustrates the peak power for each of the loads on substations 1 & 2. The maximum peak is defined as the maximal possible peak of the day, based on time and occurrence (i.e. the peak of PV and the peak of households do not occur simultaneous).

The transformers in the distribution network are dimensioned such that a physical congestion problem is not occurring (after all, there is guarantee flexibility will be available when necessary). Therefore, the congestion management solutions are tested as if the transformer is of a smaller size. On the EVCP feeders of substation 1 & 2, congestion can theoretically occur. The aggregated power of the EVCPs is 301kVA on substation 1 & 258kVA on substation 2 respectively, while the feeders have a power rating of 173kVA. Most currently available EVs charge at a lower rate. Uncontrolled congestion in an operational environment is therefore not expected.

The congestion level is set to 250kVA for substation 1, and to 400kVA for substation 2. A short-period (i.e. 2 hours) transformer overloading of 30% will be allowed. Based on these congestion levels, the total charging power of the EVCPs behind substation 1 will be limited significantly during evening peak hours. In an extreme case, it is attempted to postpone all

TABLE I
PEAK POWER PER LOAD ON SUBSTATIONS 1 AND 2. THE MAXIMUM PEAK ILLUSTRATES THE MAXIMUM POSSIBLE PEAK OF THE DAY, BASED ON TIME OF OCCURRENCE

	Substation 1	**Substation 2**
Households	277 kVA	218 kVA
SSU	-	173 kVA
EVCP	173 kVA	173 kVA
PV	268 kVA	-
Maximum peak	**450 kVA**	**564 kVA**

charging activities for the duration of the peak. At substation 2, the flexibility sources dominate the peak, which can occur through a broader time-window. Here, up to 164kVA of flexibility is needed in the worst-case scenario.

E. Measurements

Measurement equipment is installed at substation 1 and 2, on both the transformer (LV side) and all outgoing LV feeders. The measurements on the transformers and LV feeders consist of 15-minute averaged values of the voltage per phase, the current per phase, the active & reactive power per phase, bidirectional energy throughput, and total harmonic distortion. The measurements are sent to a central database every 15 minutes.

The other MV/LV substations in the Strijp-S area are also equipped with measurement devices. Of all substations a minimal dataset is available, consisting of voltage, power (active & reactive), and energy throughput measurements. All measurements are averaged over a 15-minute period. A more elaborate overview of the measurement equipment and available measurements can be found in [12].

F. Roles

For the field implementation three roles can be distinguished, namely the DSO, the commercial aggregator (CA) and the local aggregator (LA).

The role of the DSO is defined by [13], as responsible for operation, maintenance, and where necessary development of the distribution network in its area, including the connections to the higher level systems (i.e. transmission system). This includes enabling the availability of adequate network capacity and ensuring the network's stability criteria are met.

The role of the CA is defined as *"a demand service provider that combines multiple short-duration flexibility sources for sale or auction in organized energy markets."* [12]. Examples of such markets are the ancillary service markets and wholesale markets. In the Interflex project, a local flexibility market for the DSO is added.

The LA has the responsibility *"to collect and bundle (geographically) local flexibility into a bigger aggregated flexibility offering, and to provide this to a commercial aggregator."* [12]. An LA can do this by contracting flexibility sources.

As can be observed, the role of aggregator is split into two independent roles. This opens opportunities for actors interested in only the infrastructure or market trading, while leaving equal opportunities for actors interested in both roles.

G. System architecture

Within the demonstration, the DSO will obtain flexibility through two mechanisms, namely a variable connection capacity, and a local flexibility market. The variable connection capacity is limited to the SSU, while the flexibility market is implemented for all available flexibility sources. Fig. 5 provides a schematic overview of the overall architecture, including both the flexibility market and its systems, as also the interface of the variable capacity.

Two CAs and two LAs are participating, operating the flexibility sources in the field, and trading with this flexibility on the energy markets. One CA/LA pair is focusing on EVCP, while the other CA/LA pair is focusing on the PV and SSU.

To obtain flexibility from the local flexibility market, various systems are implemented. These systems are the grid management system (GMS, operated by the DSO), flexibility aggregation platform (FAP, operated by the CA), and local infrastructure management system (LIMS, operated by the LA). In order to ensure scalability, interfaces between two systems are standardized. These interfaces are elaborately described in [12].

The GMS system is used by the DSO to determine the amount of needed flexibility for each location in the distribution network, and to send corresponding flexibility requests to the CAs in the local flexibility market. This is done both in day-ahead (stage I), and intraday setting (stage II).

The FAP is the front-end system used by the CA to interface with the LA and the DSO, and its own portfolio optimization and wholesale market trading systems in the background. Wholesale trading and portfolio optimization by the CA, including the interfaces to a CA's balance responsible party are outside the scope of this work, and assumed priory established.

The LIMS system is used to standardize the interface between the LA and the CA, while different protocols are used to connect a LIMS system to the (various) flexibility sources in the field. In the future, support for additional flexibility sources can be added to the LIMS, while the interface to the CA remains standardized.

It can be observed that the local flexibility market is following a top-down methodology. The DSO requests flexibility from the CAs, who in turn determine if flexibility can be provided by the contracted LA's flexibility sources, and at which price, returning an offer. A CA has the option to trade on other markets, rather than with the DSO, leaving the possibility of unresolved flexibility need. All unresolved flexibility needs are logged. To investigate a mitigation measure for the risk of unresolved flexibility need, the (bottom-up) mechanism of variable connection capacity is added to the mix. For this mechanism, the DSO provides a signal to the PoC, limiting the connection capacity for a period in an obligatory manner. This in turn puts a constrain on the flexibility source, which through the chain will reach the CA.

Furthermore, communication failures in one or more systems are logged, and the flexibility sources will continue operating according to the last received set-points.

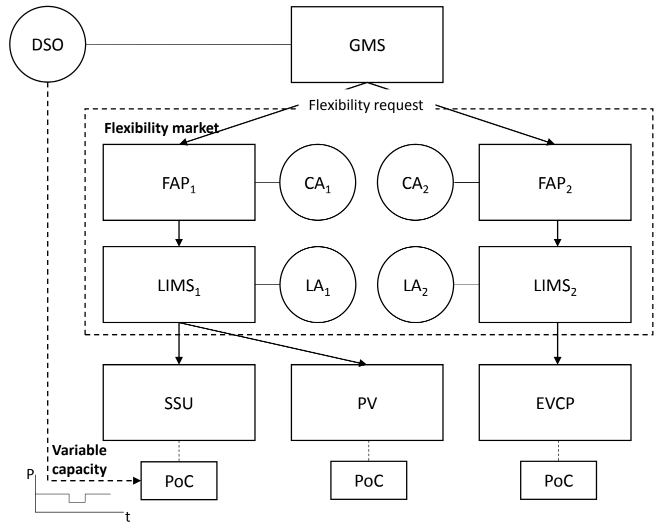

Fig. 5. Architecture of the Interflex Eindhoven demonstration, applying multiple parallel flexibility mechanisms, and a multiple aggregator market.

H. Scenarios

Four scenarios will test the two flexibility mechanisms in different stages. By evaluating multiple scenarios, insight in the added value of the various combinations are given.

Scenario 1: For scenario 1, a day-ahead flexibility market is implemented. As discussed in section III, flexibility will on a daily basis be requested using one iteration. The aggregators in the market can trade with any party interested in flexibility, without the obligation to provide it to the DSO. The expectation is that during times the DSO has a congestion problem, prices in those other markets are occasionally higher. Whether the DSO can compete with these markets, and how often the congestion problem can be solved will be evaluated.

Scenario 2: As discussed, it is expected that the DSO cannot always compete with other markets. Therefore, a static variable connection capacity is implemented in parallel to a day-ahead flexibility market. This is done for only one connection, namely the SSU. The off-peak capacity remains 173kVA, while the on-peak capacity is set at 123kVA, for an interval of three hours starting at 17:00. The expectation is that the congestion problem will be reduced, either bypassing or reducing the need for a flexibility market. The day-ahead market will operate as described in scenario 1.

Scenario 3: Since the peak loading is becoming less time-dependent due to the added flexibility, the next step will be to shift from a static variable connection capacity to a dynamic variable connection capacity. The interval of 3 hours, and the on- and off-peak capacity remain the same as in scenario 2. The starting time of the on-peak interval is set dynamic, for each day, in a day-ahead setting (8:00). The day-ahead flexibility market will operate as scenario 1. It is expected that the daily peak will be better matched in scenario 3, reducing the need to participate in the flexibility market.

Scenario 4: So far the congestion problem is tackled in a day-ahead manner, both for the variable capacity and for the flexibility market. Scenario 4 stacks an intraday flexibility market on top of the mechanisms in scenario 3. It is expected that the DSO will shift part of the trading to the intraday flexibility market. Day-ahead, the variable connection capacity sets the on-peak interval on the forecasted peak, and in an intraday setting additional flexibility is procured to compensate for errors in the day-ahead expectations. The extent in which the DSO is able to procure this flexibility will be monitored.

Each scenario will be evaluated and compared based on a number of criteria. Among these criteria is the ability of the DSO to obtain flexibility, the certainty this flexibility is available at the agreed time and location, the cost of flexibility, and the complexity of the solution. All evaluations will be made in relation with the frequency of congestion.

VI. Outlook

The field implementation of the Dutch Interflex demonstration is ongoing at this moment. This paper addresses the choices and steps that are being made. The expectation is to have all systems live in the course of 2018. The first results will be published by the end of 2018. Part of that work will address the methodology the GMS uses to trade with the flexibility market.

In addition to the congestion problem addressed in this paper, future research into adding voltage regulation to the market trading mechanism is planned. Furthermore, the scalability of flexibility resources and congestion points (for example to MV feeders) are additional future work.

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