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DSO service evaluation

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Experimental Distribution Grid Congestion Prevention through Flexibility Services

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GLOSSARY

BRP balance responsible party 2

DER distributed energy resources 1–3, 8–10
DSO distribution system operator 1–4, 6–11

EV electric vehicle 1, 2

HP heat pump 1

ICT information and communication technology 1, 2

MV medium voltage 1

PV photovoltaic 1, 2

TCL thermostatically controlled load 2, 4
TSO transmission system operator 2

I. INTRODUCTION

A. Aim and Approach

The main objective of the DSOs (distribution system operators) is to guarantee power delivery with an appropriate quality to the end consumers, by effectively balancing two objectives: reliability and cost efficiency of distribution grid operation. DSOs design and operate the grid with extra capacity in order to reduce the impact of unexpected situations such as faults or exceptional load demand. For instance, when faults occur in the MV (medium voltage) grid, reconfiguration is used to bypass the fault and restore supply to as many disconnected customers as possible. This reconfiguration can increase stress on the grid and potentially lead to overloading and voltage issues. One way for a DSO to avoid voltage violations or overloadings is to reinforce the grid so that it is able to handle such operational issues. However, since such situations occur rarely, this solution is in most cases uneconomical and would leads to largely unnecessary grid reinforcement. This paradigm is now changing, also due to the technological developments. It may be more cost effective to buy services that change consumption for the duration where congestion conditions occur.

First, lower prices have led to an increase in automation and ICT (information and communication technology). For example, customer smart meter data allows DSOs to obtain an insight into the distribution grid state. Further, through automated control, customers can easily adjust their power consumption to reduce their electricity bill or their environmental impact. However, this might synchronize loads and therefore increase consumption peaks in distribution grids. This effect is intensified by the increasing penetration of flexible loads such as residential electric heaters and electric vehicles. Second, throughout the past decades the power grid has become more reliable with an increasing cost for additional security measures.

For this purpose, EcoGrid 2.0 is developing and testing a market setup for distribution grid services facilitated by aggregators. DSOs can participate in this market to delay or avoid investments for replacement and reinforcement of transformers and power lines. This paper proposes a method to quantify the financial benefit of DSO services. This allows DSOs to decide which operational strategy is more viable - overloading network equipment, reinforcing the grid or requesting flexibility services from aggregators.

B. Literature Review and Contributions

1) Distribution grid congestions & voltage issues:

For DSOs new operational challenges such as congestions and compliance with the ±10 % voltage limits will arise from increased consumption for EVs (electric vehicles) and residential HPs (heat pumps), together with increased local production from PVs (photovoltaics). Congestions arising on the 10 kV distribution substation transformers due to high consumption from the loads connected below them, or significant voltage rises on the 0.4 kV feeders due to high levels of local generation have been already been identified as key issues [1]. As shown in [2], DSOs can use the DER (distributed energy resources)'s flexibility to tackle location-dependent problems. Grid-oriented services were investigated in [3], where the DSO decides during the planning process whether to call for a market-based procurement or to proceed with grid reinforcement. To unleash the full potential of DER flexibility, the European regulatory framework is evolving to enable interactions between stakeholders through market mechanisms [4].

2) Market approaches for distribution grid congestion management:

Market methods for congestion management employ price signals or contracts to influence the behavior of flexible demand [5]. Several papers have presented frameworks to enable multiple participants to compete for selling or buying flexibility. The authors of [3] present market-based procurement of flexibility which aims to manage local problems by exploiting DER flexibility at the distribution level in the short term, and defer or avoid grid investments on additional capacity in the long-term. Authors in [6] present a similar centralized local flexibility market approach, where an aggregator manages flexible loads to provide services to the DSO and BRPs (balance responsible partys).

To achieve this goal, this work proposes a setup in which the DSO procures flexibility services from aggregators. The proposed DSO framework and market design is being demonstrated in practice in the context of the EcoGrid 2.0 project [7] on the Danish island Bornholm.

C. Paper Organization

The remainder of the paper is structured as follows:

In Section II, the EcoGrid2.0 project is described and the flexibility services are defined along with their parameters. In Section III, the methodology to identify the requirements of flexibility for congestion prevention is introduced. In Section IV, a real medium voltage feeder is used to demonstrate the concept. Section V presents the results of the conducted experiments and concludes the paper.

II. The EcoGrid 2.0 Project

EcoGrid 2.0 is a project that demonstrates how private households can offer power system services for both the TSO (transmission system operator) and the DSO through demand response. Around 1000 private households from the island of Bornholm participate in the project. All project participants are equipped with smart meters and own a flexible electric heating unit with communication/control equipment. Historical load values of all smart meters are available since the beginning of 2016. Households have a single smart meter which measures the flexible consumption together with non-flexible load and potential PV generation. An overview of the EcoGrid 2.0 project setup can be seen in Fig. 1.

The methods developed in EcoGrid 2.0 are designed for technology and equipment which will be available in Denmark by the end of 2019. All private customers in the country will be equipped with smart meters and their power consumption data will be centrally stored in the DataHub. If manufacturers equip DERs with ICT capabilities that allows remote control, aggregators will be able to offer flexibility to the TSO and the DSO at low additional cost. Such technologies are already

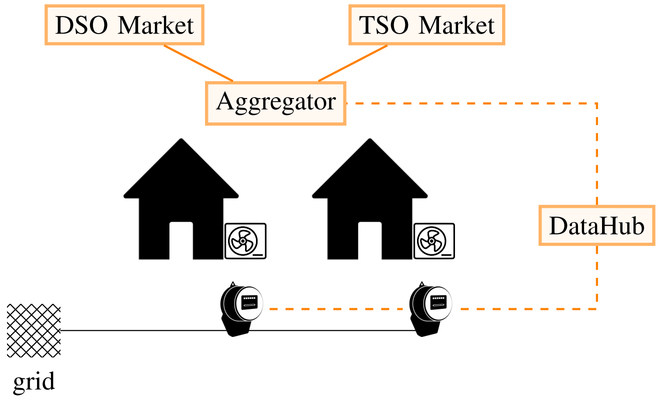

Fig. 1. Overview of the EcoGrid 2.0 setup.

pre-installed by manufacturers in most EVs and many modern heating systems.

EcoGrid 2.0 assumes that products for DSO flexibility services are traded one to twelve months in advance. To request a flexibility service the DSO has to be able to quantify how often, how much and for how long load reductions (or increases) are needed. Further, the DSO has to translate these results into standardized DSO services submitted to a market together with a price that the DSO is willing to pay for the service. The flexible load of approximately half the customers consists of resistive heaters - the other half of heat pumps. The resistive heaters are controlled by adjusting room temperature set-points, whereas for heat pumps a throttle signal can be sent and the heat pump's operation is ceased [8].

A. Definition of Flexibility Services

The EcoGrid 2.0 market setup is described in [16]. An essential characteristic of TCLs (thermostatically controlled loads) is that any load change causes a deviation from their steady-state operation. Thus, a load change (response) is followed by a load change to the opposite direction (rebound) to return to this steady state. In the EcoGrid 2.0 market, this effect is taken into account by defining two consecutive blocks, one representing the response and the other the rebound; together they form an asymmetric block offer [9]. The authors of [11] present the DSO-level service market.

EcoGrid 2.0 introduces two types of DSO services: load reductions or increases around a predefined baseline and capacity services. The baseline represents the assumed power consumption of flexible units, had the aggregator not controlled the portfolio to deliver a service. Further, services can be either scheduled or conditional. Scheduled services are always offered during the defined time period, whereas in conditional services the aggregator has to deliver the service only if an activation signal is sent by the DSO shortly before the delivery period. Payments for this service are split into a reservation part and an activation part. If a service is not activated the DSO only pays the reservation price. Flexibility services for the DSO target specific network equipment. This

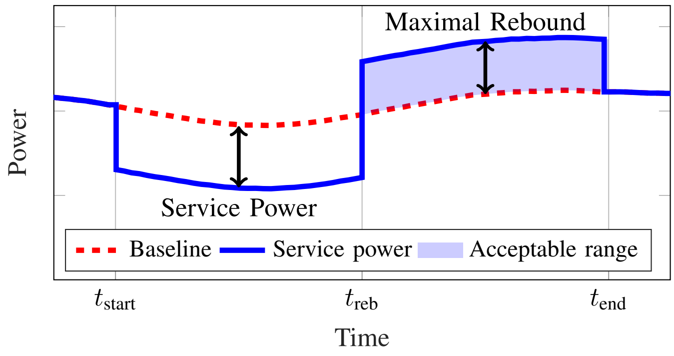

Fig. 2. Sketch of a relative DSO-service request.

means that each service can only be delivered by specific DERs that are connected to specific nodes.

In this work, we focus only on load reduction/increases, which are referred to as relative services because they are delivered with reference to the baseline consumption. More details on the baseline estimation methods used to define and verify the proposed services can be found in [2] and [12]. Figure 2 shows a load reduction service.

1) Service Request Parameters

The process of how a service is requested, sold and activated is illustrated by Fig. 3. Initially, the DSO carries out a probabilistic network assessment to create a list of potential service requests with a corresponding maximum price. All of these services address the same network issue. Then, the DSO initiates an auction by sending the list of service requests to the market operator. The market operator forwards this information to the aggregators without revealing the DSO's willingness to pay. Aggregators can send offers for each service request on the list. As service requests on the list are mutually exclusive, only one will be finally acquired. The market is cleared by choosing the most economically beneficial service request and standardized contracts are created between the DSO and the aggregators.

Each service request consists of eight parameters, which are listed in Table I. *Start time*, *Response end time* and *Rebound end time* define the time when response and rebound periods occur. Furthermore, it is necessary to include locational information to the request. Each flexibility unit in the distribution network is assigned a unique unit ID. The DSO specifies which units can deliver the service through a *List of unit IDs*. Apart from the *Maximal price paid by the DSO*, which reservation the DSO's willingness to pay for a service request, an *Activation probability* is included. Through the activation probability the DSO expresses how often it expects a conditional service to be activated. The *Activation probability* for scheduled services is equal to one. The blue line in Fig. 2 depicts the maximal desired power consumption of the aggregator, in order to deliver the service. Each power profile laying within the blue area is acceptable. The red dashed lined depicts the baseline. In this work overloading of network components, such as lines or transformers, are considered. The same methodology can also be applied to avoid large voltage fluctuations.

Parameter	Variable	Example
Start time	t_{start}	19:00:00
Response end time	t_{reb}	20:00:00
Rebound end time	t_{end}	21:30:00
Contract start time		01-Feb-2019
Contract end time		31-Mar-2019
Service power	P^{red}	150 kW
Maximal rebound	P^{reb}	50 kW
List of unit IDs		List of IDs
Maximal price (DSO)		750 DKK
Activation probability	π^{act}	0.3

TABLE I
SERVICE REQUEST PARAMETERS

III. METHODOLOGY

In Denmark, DSOs now have access to smart meter data of their customers. Ecogrid 2.0 has analyzed how available data can be used to predict grid congestions and define meaningful load reduction services to address such issues. Smart meter data in EcoGrid 2.0 is available to the DSO within 24 hours. In most cases online observation of the medium and low voltage network is not possible with the current infrastructure. Thus, the decision whether or not to activate flexibility services is based on estimates and forecasts. Subsections III-A and III-B introduce the method used to forecast whether flexibility is required for congestion prevention and what its value to the DSO is.

A. Service request

Figure 4 gives an overview of the different steps which are carried out to decide if a service from the DSO market is beneficial. The DSO has to make service requests one to twelve months in advance. For such a long time horizon, DSOs are unable to accurately predict the electric load in the distribution network. They are, however, able to estimate the range within which the load will most likely lie. Thereby the DSO can predict the risk of overloading and the economic implications associated with it. To capture this uncertainty, a *probabilistic network assessment* is carried out (black box). Load scenarios which realistically capture the uncertainty and volatility of the demand of a certain time period are generated. To assess customer behaviour during the trading period, historical load data is used. Using a grid model these load scenarios are translated into network loadings of each node in the network with a *sequential Monte Carlo power flow calculation* (red box). This results in the network loading for each scenario. Next, the operational cost of network components for each loading scenario can be estimated by using a component cost model. The expected operational cost for the considered time period is calculated, taking into account each scenario with the appropriate probability of occurrence. The expected operational cost is then used to define the list of service requests. The operational cost peak can be used to identify when services are most beneficial. Network operational costs

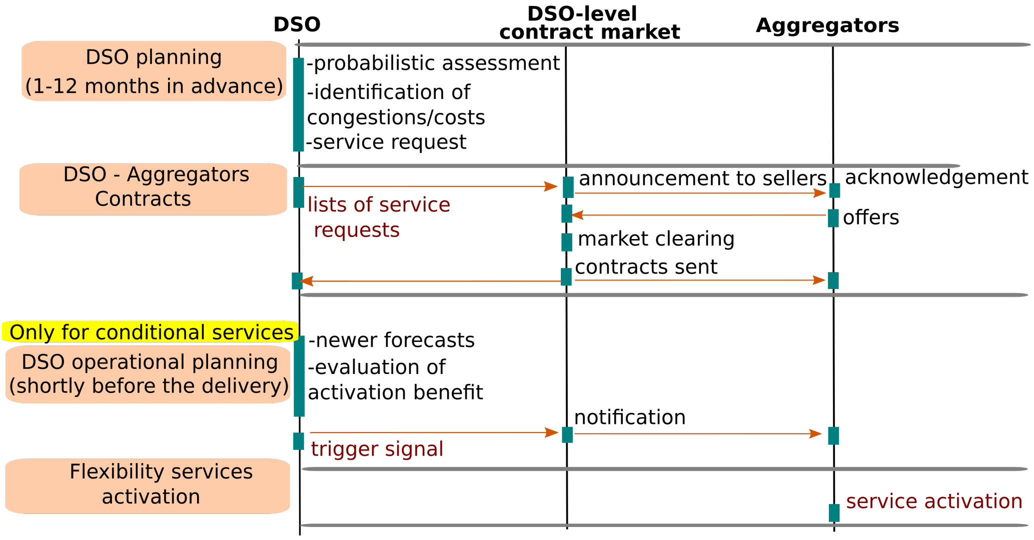

Fig. 3. Methodology overview for DSO flexibility services.

with and without service delivery are used to define the individual service request benefit (green). Finally, the resulting list is forwarded to the DSO market.

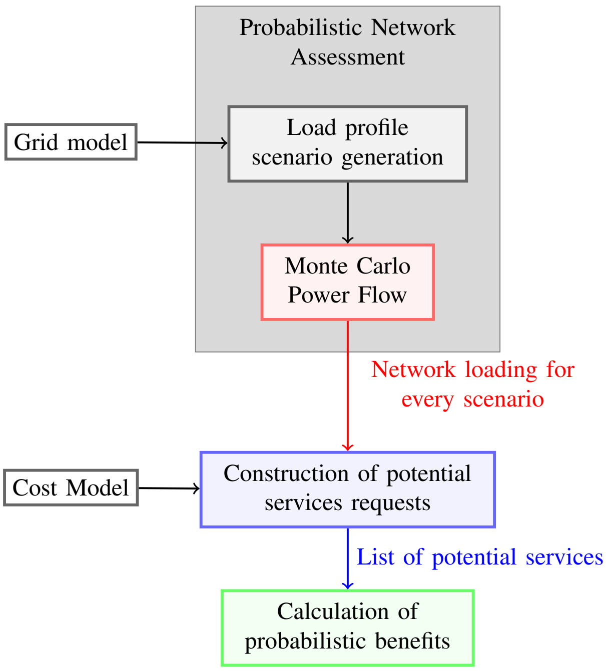

Fig. 4. Flowchart of the service request decision tool

B. Service activation

A similar procedure is followed to decide whether or not to activate a conditional service. At this point uncertainty is significantly smaller as the delivery period is much closer. In EcoGrid 2.0 TCLs are used as flexible loads. Naturally, ambient temperature is the most important input for the load forecast. The service activation signal is sent between 24 to one hour in advance. Ambient temperature forecasts for the next 24 hours are highly reliable. Therefore, the remaining uncertainty is due to the unpredictable customer behavior. Again, load scenarios are translated to equipment loading scenarios, using a Monte Carlo power flow calculation. The expected network operational cost with service activation is compared to the cost without activation. If the expected activation benefit is higher than the service activation price the trigger signal is sent to the aggregators.

C. Probabilistic Network Operational Assessment

As shown in Fig. 4, the proposed method requires scenarios to estimate the uncertainty and variability of load demand. During the grid planning stage, DSOs are interested in extreme scenarios, which occur rarely and are therefore not necessarily represented in a historical data set. For example, unprecedented events, such as particularly cold and cloudy winter days, may not exist in the available historical data. Instead of trying to forecast the actual load, DSOs can identify the range and probability for network overloading. This section describes how a DSO can create load scenarios based on historical data which also include rare or unprecedented load events.

1) Load profile scenario generation

To create load scenarios we use past smart meter data, aggregated at the secondary substations, and apply a decomposition technique from [13], which is built on local regression smoothing. Decomposition divides load into three parts - trend, seasonal variation and residual. The trend component is mainly dependent on the ambient temperature and is used to capture its uncertainty. The seasonal component represents daily variations. The residual part is used to capture uncertainty of customer behavior and other random influences. The result of

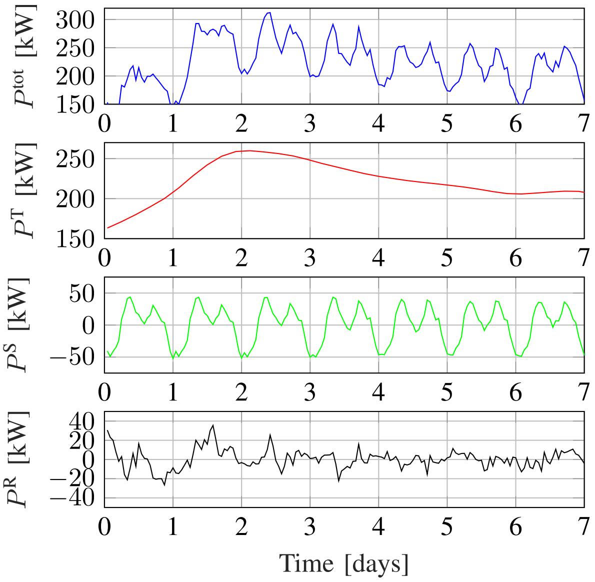

Fig. 5. Decomposition of aggregated consumption of 191 households in January.

such a decomposition for an aggregation of 191 households during January is shown in Fig. 5. The top plot (blue) shows the total aggregated power consumption for one week P^{tot} . This power consumption is split into the three parts: a general trend P^{T} (red), a seasonal daily part P^{S} (green) and a residual P^{R} (black). These terms add up to the total power consumption as

$$P^{\text{tot}} = P^{\text{T}} + P^{\text{S}} + P^{\text{R}}. \quad (1)$$

Table II shows the correlation of ambient temperature and solar radiation with the different components of the decomposition based on data from 2016.

	P^{T}	P^{S}	P^{R}
Ambient Temperature	-0.91	0.013	-0.15
Solar radiation	-0.001	0.17	-0.10

TABLE II
CORRELATION OF SOLAR RADIATION AND AMBIENT TEMPERATURE WITH TREND, SEASONAL COMPONENT AND RESIDUAL

Trend term P^{T} is strongly correlated with ambient temperature. For each month a linear model is fitted, such that trend P^{T} can be expressed as a function of ambient temperature T^{ambient}.

$$P^{\text{T}}(t) = \alpha_1 T^{\text{amb}}(t) + \alpha_0 \quad (2)$$

Loess-smoother is applied to the profile [14] to smoothen the temperature profile. Fig. 6 illustrates the concept for January. The top graph depicts ambient temperature, both the real data (black), as well as the smoothed profile (red). The lower graph shows the trend part from the decomposition. The blue line represents the result from the decomposition and the red line shows the fitted model during the same month, on the basis of smoothed ambient temperature profile. To test the

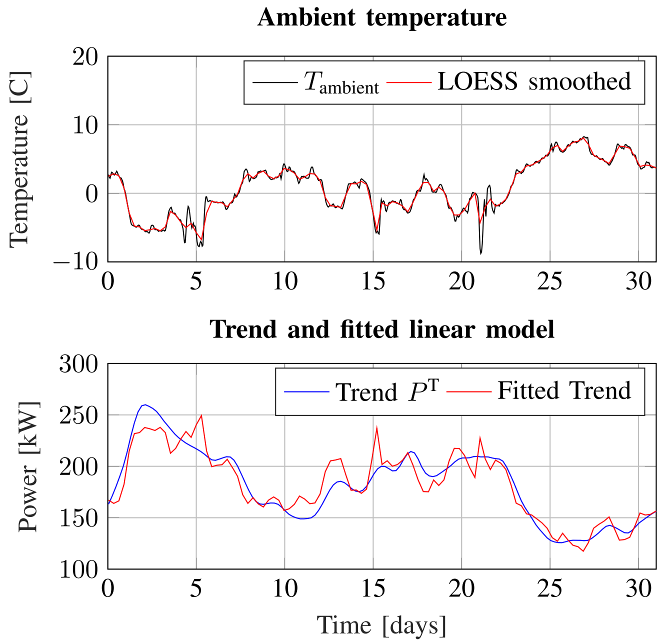

Fig. 6. Top: Ambient temperature of January 2016. Bottom plot depicts trend P^{T} for January (blue) together with the fitted linear function of the ambient temperature (red).

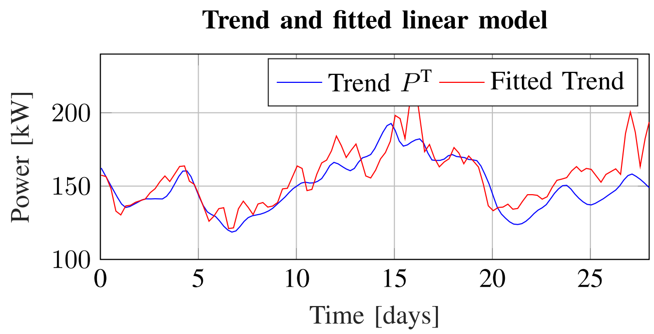

Fig. 7. Linear trend modelling of January 2016 applied to the trend profile of February 2016.

procedure, we apply the model from January to data from February. The resulting trend is shown in Fig. 7.

Apart from ambient temperature and trend P^{T}, no other significant correlations were identified, hence the remaining uncertainties will be captured through Monte Carlo simulations. Feeders with a strong PV-penetration might have a strong influence of solar radiation on the trend and seasonal component of the decomposition. In this case, a similar approach as for temperature can be introduced to capture this dependency.

Residual P^{R} is auto correlated. To capture this feature, we fit a seasonal ARIMA model with one hour averaged values. The resulting auto correlation function, the differenced auto correlation function and the partial auto correlation function are shown in Fig. 8. Plots show a strong auto correlation and strong seasonal components. Using the AIC-criterion, a

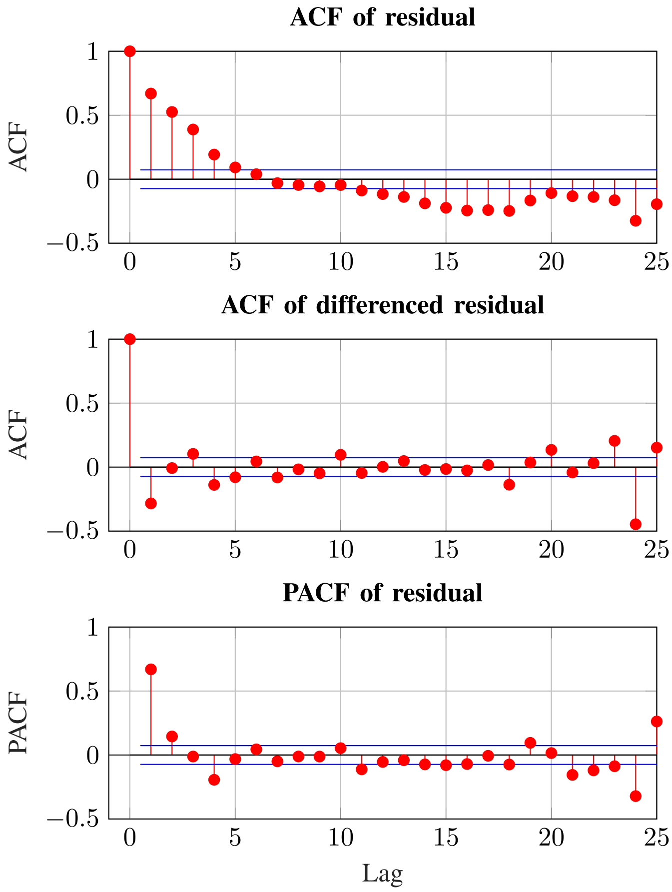

Fig. 8. Auto correlation function of P^{R} (top), ΔP^{R} (middle), and partial auto correlation function of P^{R} (bottom).

$(2,0,2)\mathrm{x}(2,0,2)_{24}$ is chosen to model the residual part of the decomposition. The model can be expressed with backwards shift operator B and interpreted as the lagged variable as

$$\begin{aligned}\left(1+\Phi_1 B^{24}+\Phi_2 B^{48}\right)\left(1+\phi_1 B+\phi_2 B^2\right) P_t^{\mathrm{R}} &= \\ \left(1+\Theta_1 B^{24}+\Theta_2 B^{48}\right)\left(1+\theta_1 B+\theta_2 B^2\right) Z_t, &\end{aligned} \tag{3}$$

where Z_t is the normally distributed noise term. Φ and Θ are the seasonal parameters, and ϕ and θ the non-seasonal parameters. Fig. 9 shows the quantile-quantile plot of the ARIMA residuals. There seems to be only a very slight deviation from perfect random distribution and we can assume that the ARIMA residuals are normally distributed. The Ljung-Box test of the residuals leads to a p value of 0.4, indicating that the ARIMA residuals are not significantly correlated.

To generate load scenarios, n^{temp} scenarios for the ambient temperature are created and translated into trend samples using (2). To each trend scenario, the seasonal part is added, which is based on the decomposition of historical data. Finally, n^{res} residual scenarios are created by choosing a set of random variables Z_t for each temperature sample resulting in a total number of $N = n^{\mathrm{temp}} n^{\mathrm{res}}$ load scenarios. These N scenarios are used in a Monte Carlo-based power flow simulation, which results in a set of N load flows.

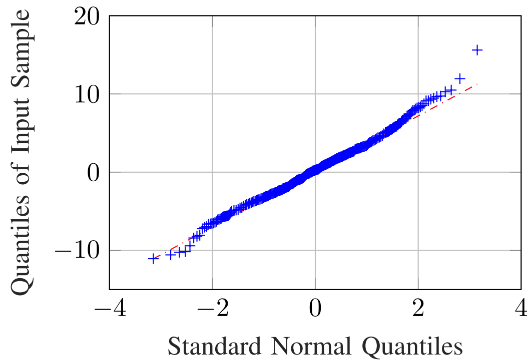

Fig. 9. Quantile-quantile plot of the residuals of the fitted ARIMA model.

2) Cost model-Network Operational Cost Function

Each network component has a rating, which is usually expressed in the form of a nominal current or power. Short intervals where these limits are exceeded reduce the life time of the component, and can potentially cause an outage (mainly related to tripping of protection). Long intervals where these limits are exceeded cause permanent damage to the components. Models for the reduction of life of transformers are widely used and are based on the concept of hottest spot temperature Θ^{H} , which depends on the ambient temperature, the top-oil rise over ambient temperature and the winding hottest-spot rise over top-oil temperature [15]. To calculate the top-oil rise over ambient temperature at time t, the transformer loading at time t is used. Every transformer temperature is dependent on the temperature in the previous time step. The change in temperature can be modelled at every time step, based on the transformer specific parameters which describe the heat flow time constants. In this work we focus on grid services designed to reduce the stress on transformer stations. However, cost models are available for power lines and cables and the method can easily be expanded to cover such components.

According to [15], the aging acceleration factor in percent F_{tr}^{aa} at time step t is described by

$$F_{tr}^{\mathrm{aa}}(t) = \exp\left[\frac{15000}{383} - \frac{15000}{\Theta^{\mathrm{H}}(t)+273}\right]. \tag{4}$$

Assuming that transformer replacement costs are C_{tr}, then each transformer loading can be translated to a cost $OC_{tr}(t)$ as

$$OC_{tr}(t) = \frac{F_{tr}^{\mathrm{aa}}(t)}{100} C_{tr} \tag{5}$$

Repeating the calculations for every generated scenario, the expected operational cost EOC^* can be calculated as the average of the operational costs of all scenarios. Time steps with very high EOC^* indicate times when the acquisition of a DSO service could potentially be a more viable solution.

D. Construction of list of potential service requests

Network operational cost can be calculated for each time step of the time period in question. The following steps define how the list of DSO service requests was created in EcoGrid 2.0:

1) Identify the hour when $EOC^*(t)$ is maximal. Start the response period 30 minutes earlier.
2) Define a response power RP starting from 10 kW, in steps of 10 kW until 160 kW.
3) Define a rebound duration of 30 minutes for five different maximal rebound values of $0\%, 25\%, ..., 100\%$ of RP. 30 minutes is chosen here since tests in EcoGrid 2.0 have shown that rebounds usually do not last longer.

E. Calculation of probabilistic benefit

The cost of each scenario can be evaluated both with and without a DSO service and the cost difference can be interpreted as the DSO's benefit of that particular service request. In the context of EcoGrid 2.0, only the cost of network overloading is taken into account, represented through equipment replacement cost. However, more complex network operation cost functions representing voltage violation costs, expansion costs, network reconfiguration costs etc. could potentially be included. The benefit of a service request is defined as the savings that the DSO would have during network operation if it was applying the flexibility service. Hence, the reference case is represented through grid operation without DSO services leading to expected network operational cost EOC^{ref}. This cost is compared to the case where the DSO has requested a flexibility service fs, with an expected network operational cost EOC^{fs}. The expected benefit EB^{fs} for the specified service request fs is given by the difference of these two costs:

$$EB^{fs} = EOC^{ref} - EOC^{fs} \tag{6}$$

Evidently, a service would not be requested when EB^{fs} is negative. Figures 10 and 11 illustrate the procedure to calculate the expected service benefit. For simplicity, the procedure is plotted for only one day with three load scenarios.

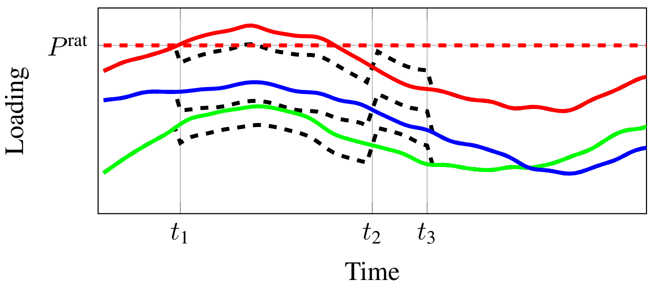

Fig. 10. Sketch of a scheduled load reduction - blue, red and green lines depict load scenarios, the black line represents a load reduction service

If the activation probability is equal to one (Fig. 10), meaning that the flexibility service is scheduled, the service is activated under all circumstances. The load reduction and the following rebound is applied to all load scenarios and the cost is compared with the reference case to calculate the expected benefit. The service (black dashed line) is applied to all scenarios, regardless of the fact that it is not very

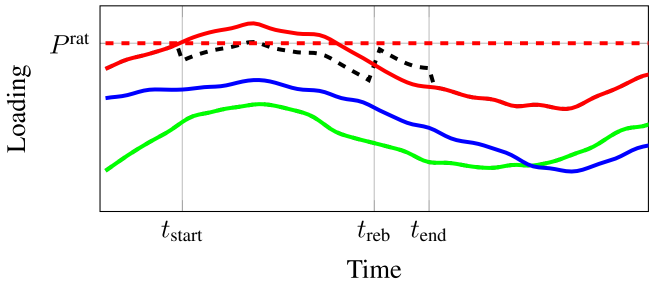

Fig. 11. Sketch of a conditional load reduction - blue, red and green lines depict load scenarios, the black dashed line represents a load reduction service

beneficial for many samples. When the activation probability is smaller than one, calculating the benefit of this service is more complicated. Since the service is applied to only a share of the scenarios, specifically in Npi^{prob} cases, the DSO has to value the option of activating the service. To make a realistic estimate of this benefit, $N\pi^{\text{prob}}$ scenarios with the highest cost during the activation period are chosen for service activation. Figure 11 illustrates this for an activation probability of 33 %. The highest cost occurs in the red load scenario. Due to the activation probability of 0.33, the service is only activated in one third of all cases. Again, to calculate the expected service benefit, the operational cost of all scenarios is averaged and compared to the reference case.

In EcoGrid 2.0 it was assumed that a DSO intends to use its grid close to nominal rating. Hence, activation probabilities were defined as the ratio of load scenarios which exceed rating in the activation period. DSOs might intend to have lower line and transformer ratings, and therefore activate services more frequently. Since the cost of operating network equipment significantly below its rating is low, conditional service requests and scheduled service requests grant similar benefits to the DSO. This does not necessarily mean that these two service requests will cost the same, since the cost for offering conditional load reductions are significantly lower on the aggregator side. It only represents the fact that the DSO's willingness to pay is similar for both service requests, as both services in principle successfully prevent grid violations.

F. Activation benefit evaluation

If a DSO acquires a conditional service, each day it has the option to activate it. Each time this happens, the DSO has to pay an activation fee to the aggregators. In order to decide whether or not to activate a service request, the DSO has to compare the expected service activation benefit to the activation cost. Activation costs are specified by the aggregators as part of their bids, hence the final activation cost is determined by the outcome of the market clearing. The samples generated close to activation have a much smaller uncertainty, compared with the network operational planning stage, since reliable weather forecasts are available.

In the EcoGrid 2.0 market setup, the DSO specifies an activation probability for conditional service requests. The risk of the DSO deviating from this specified activation probability by activating conditional services more or less often, is carried by the aggregators. Thus, aggregators have the incentive to specify their real reservation cost, as well as their real service activation cost in their bids.

IV. Case study

A. Network Description and Specification

For the EcoGrid 2.0 project, a real representative medium voltage feeder has been selected to demonstrate DSO services. An overview of this distribution feeder can be seen in Fig. 12.

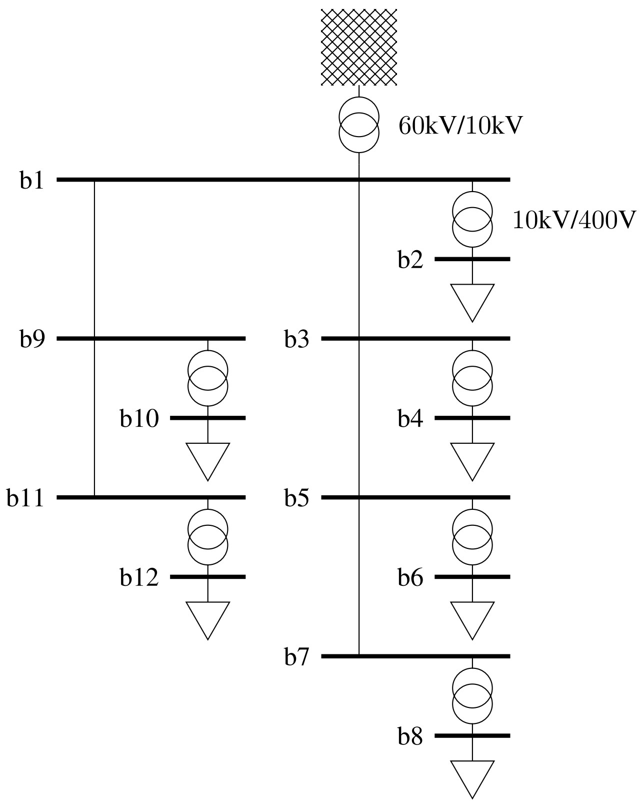

Fig. 12. Distribution grid model

The feeder has seven substations in total, one with a 60 kV/10 kV transformer and six transformer stations connecting the 10 kV level to the 400 V network. A total of 564 residential customers are connected. 5.07 km of medium voltage network and a total of 3.03 km of low voltage network have been modelled. 27 EcoGrid 2.0 participants are physically connected to the chosen feeder. As 27 participants are too few to offer reliable DSO services, 310 additional EcoGrid 2.0 participants from the island Bornholm are assumed to be located on this feeder as well. Customer power consumption profiles are aggregated at the corresponding 10 kV - 400 V transformer stations. To simulate a congestion, the rating of the 60/10 kV transformer station has been artificially reduced to 1300 kW.

Residential heating is mainly used during winter months. In distribution feeders with a high share of electric heating, these are also the months when the highest load peaks occur. EcoGrid 2.0 has tested the DSO service market in the winter months of 2018/2019. 39 times the DSO successfully requested load reduction services from the local DSO market. To test a variety of services, these were not requested with the specified lead time of one to twelve months. However, when requesting services only at least one year old information was used. This way it was possible to carry out a large number of tests, while still facing the uncertainties that are caused by large lead times. For the service activation decision, all available data, including recent smart meter values as well as weather forecast for the next 24 hours, was used.

V. Results

Figure 13 presents the results of one DSO service which was delivered on the 25th of January 2019. The electric heaters of 121 households were controlled to reduce load by 90 kW on the transformer station between $16.00 - 17.00$. The top graph shows load uncertainty one year and one day before service delivery in the form of minimum/maximum values from all generated scenarios. One year in advance, weather conditions are still entirely uncertain. In January, typical temperatures on Bornholm vary between $\pm 10°$. Heating consumption in residential houses is very low when outside temperatures are close to $10°$, whereas heaters operate almost at full power when ambient temperature is around $-10°$. Transformer load can therefore lie anywhere between 550 kW and 1550 kW, covering an interval of 1 MW. The worst case scenario exceeds the transformer rating by about 250 kW. Due to this fact, the DSO initiates the market by sending a list of service requests to the market operator. The cleared service consists of a 90 kW power reduction followed by a 54 kW maximal rebound.

One day ahead of service delivery temperature forecasts are quite accurate. The remaining uncertainty is now reduced to around 200 kW and is mainly due to random customer behavior. In the worst case, the total power flow on the transformer station would exceed its rating. Accordingly, the expected transformer loading cost is higher than the service activation cost. The real power flow on the transformer station is depicted by the blue curve and the baseline by the red curve. The middle graph shows the aggregated power consumption of the DERs delivering the service. While the service was designed to reduce power consumption at the transformer station, the aggregator has no access to measurements at this node. The service is verified with the smart meter data of the DERs offering the service, which is available to both parties - DSO and aggregator. Finally, the bottom graph shows the cost on the transformer station. The blue and red curves depict the costs based on the real power flows on the transformer and the baseline case, respectively.

Figure 14 shows the logarithmic histograms of the service benefit forecasts for each load scenario. The top graph for one year in advance and the bottom graph one day before service

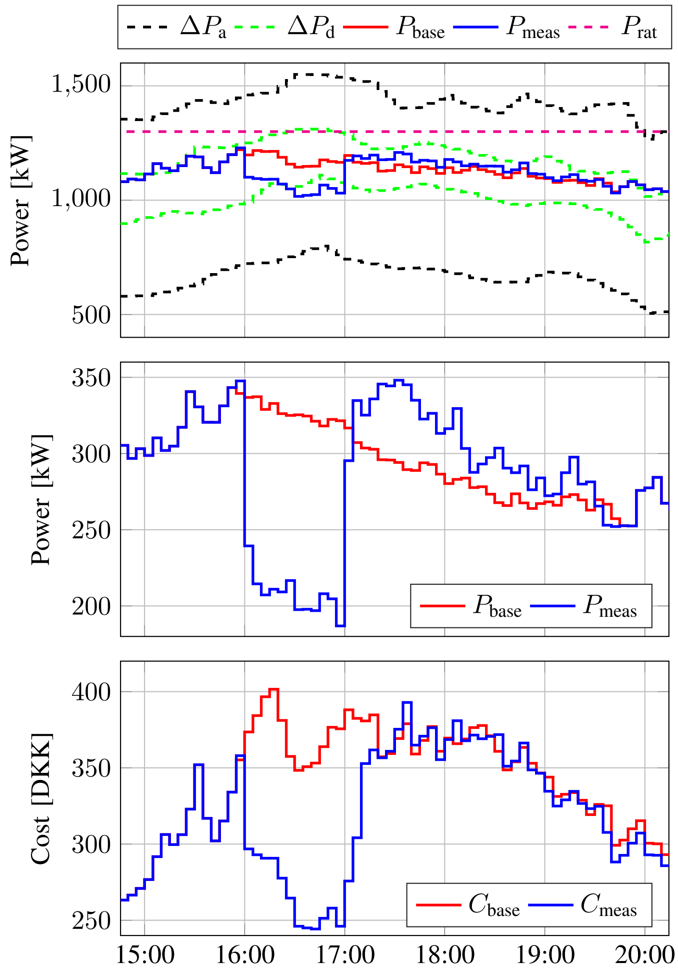

Fig. 13. DSO service delivery on the 25th of January 2019. Top: power flow on transformer station, middle: aggregated DER power consumption, bottom: modelled cost of transformer loading

activation. In both graphs the red line represents the average (or else the expected) benefit of this service.

The expected benefit with one year lead time is 238 DKK. One day before service delivery it is clear that ambient temperature will be slightly lower than usual. The expected benefit therefore increases to 259 DKK. The final calculated benefit of this particular service was 1746 DKK, due to the fact that aggregators reduced the load significantly more than was contractually agreed upon (the load decrease was 123 kW on average, while the service was planned with 90 kW reduction).

Figure 15 shows another example of a DSO service, which was delivered on the 22nd of February 2019. A 100 kW load reduction followed by a maximal 75 kW of rebound was cleared by the market. The service was supposed to be delivered one hour later, at 17.00 o'clock. The expected benefit of this service at the time of service request was 577 DKK. The most likely temperature during this period is around zero degrees. Close to service activation, temperature was warmer (5°), such that the DSO predicted a smaller benefit for service activation (310 DKK).

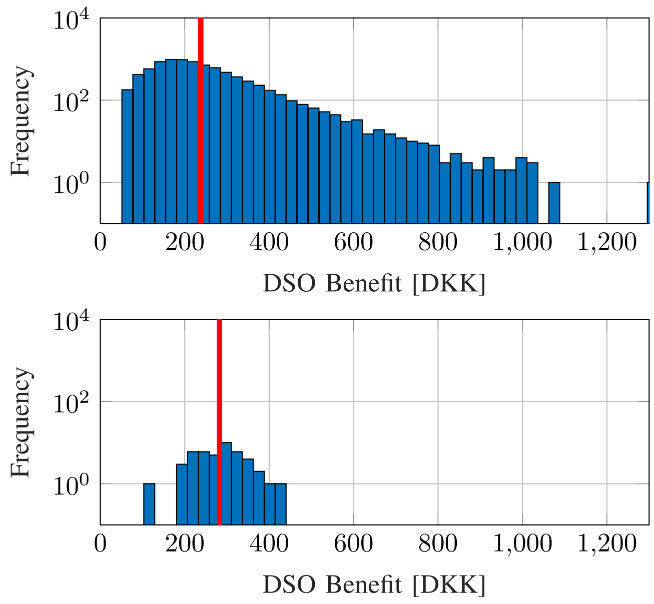

Fig. 14. Logarithmic histogram of service benefit for DSO service at the time of request (top) and activation (bottom).

Figure 16 again shows the logarithmic histogram of the service benefits for all the created load scenarios. As the risk of extremely low temperatures in February is higher than in January, the expected benefit of grid services in February is also higher than in January. In the worst scenario a DSO service would create a benefit on the DSO side of about 4000 DKK. The expected benefit of a service in this case is also higher than before. One day before service delivery it was already obvious that such extremely low temperatures would not occur. Even though the expected benefit of service activation was low, the DSO chose to activate the service anyhow, as aggregators had specified an activation price of zero.

The overall accuracy of DSO services is fairly high. Figure 17 shows the delivered service response on the y-axis against the initially requested response. The red curve indicates the $y = x$ line, which presents the ideal delivery. Overall DSO services in EcoGrid 2.0 were delivered with an accuracy of 18 %.

Note, that in this graph the requested power was corrected based on the amount of successfully activated houses. This was done in order to evaluate the potential accuracy of DSO services by excluding the errors induced through communication failures. The errors, which are included incorporate the baseline uncertainty for small aggregations as well as errors from the aggregators flexibility model.

Under the assumptions, which were made in this work (heavily loaded transformer station and feeder with a large share of flexibility), the total benefit of all DSO services in this project amount to 7700 DKK.

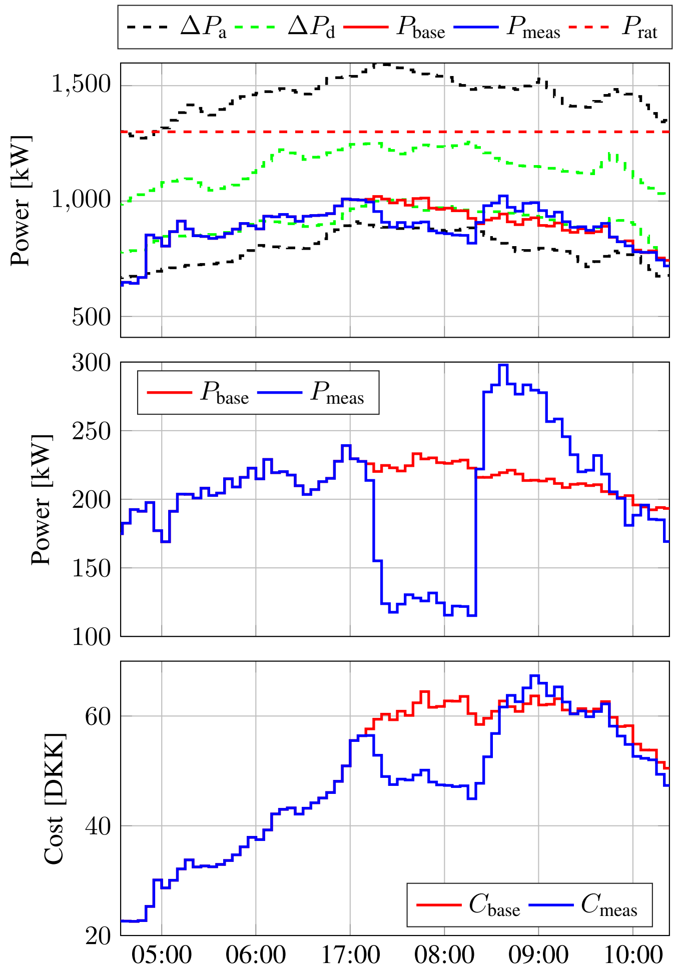

Fig. 15. DSO service delivery on the 22nd of February 2019. Top: power flow on transformer station, middle: aggregated DER power consumption, bottom: modelled cost of transformer loading

VI. Discussion and Conclusion

In this report, a method to quantify the benefit of DSO services has been proposed. This benefit can then be used to decide whether or not to request services on a DSO service market platform. In the same manner service activation benefit was defined, which is used to decide, whether or not to activate a conditional load service.

In EcoGrid 2.0 a market approach was chosen. The main benefits of a market approach are that products, in this case flexibility, are allocated in an optimal way, maximizing the social benefit of the system as a whole. In [16], it was specified, that a DSO only sends one market request together with its maximal willingness to pay for this particular service request. However, as this report shows, there are many different potential service solutions to network equipment overloading. Regular network overloading can be tackled with different service powers, rebound powers, service duration, and even different delivery hours. The DSO is only able to quantify its benefit of a service request. Without taking into account,

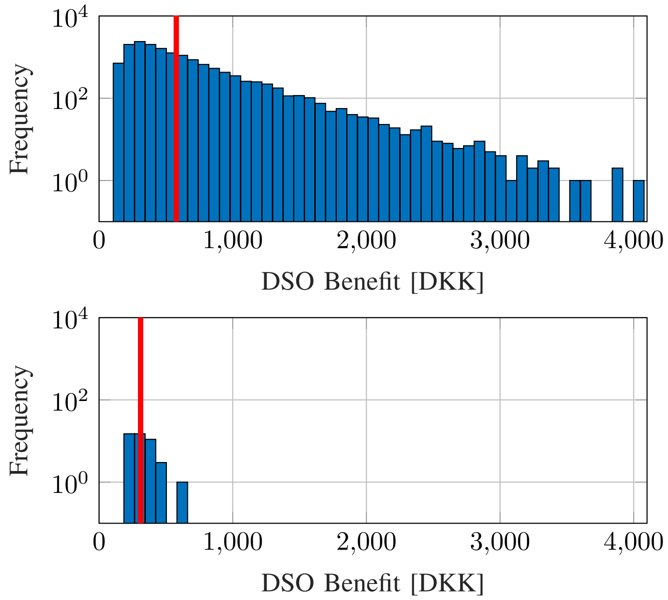

Fig. 16. Logarithmic histogram of service benefit for DSO service at time of request (top) and activation (bottom).

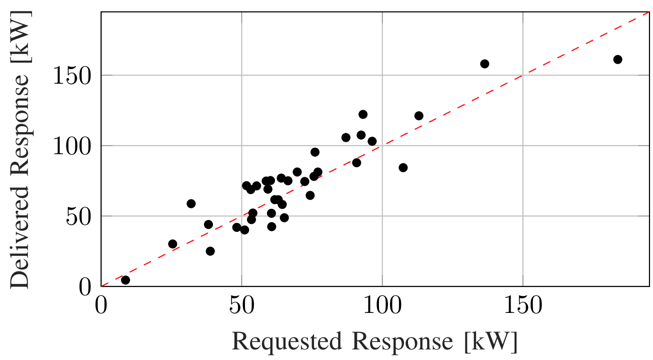

Fig. 17. Delivered service response vs. requested service response of 34 DSO services.

the costs, which arise on the aggregator side, the DSO is not able to reasonably reduce the list of potential service requests to a single service request. Due to this fact we have moved away from the market specification in D2.2, such that the DSO sends a list of DSO service requests to the DSO market. These service requests are mutually exclusive and only one service will be sold. Aggregators make bids for all service requests and finally the market is cleared through an optimization problem, such that the social benefit is maximized.

While the proposed method was developed to tackle congestion issues only, it can be expanded to tackle voltage issues in the distribution grid as well. It is also suitable if the DSO does not have online information about the distribution grid state available.

Experiments have been conducted, which showed, that given a feeder with a large penetration of residential heating, aggregators can reliably deliver load reduction services to the local DSO.

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