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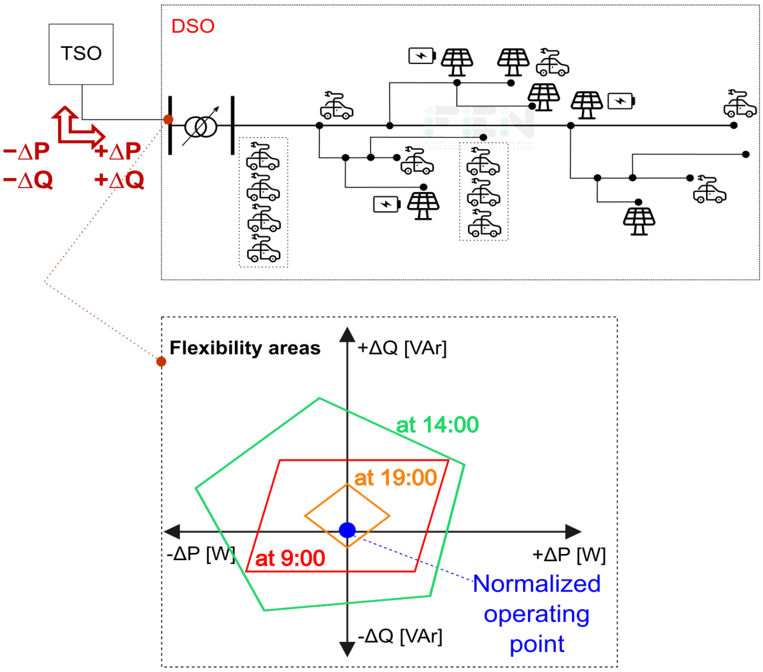
Final report

TSO-DSO Flexibility: towards integrated grid control and coordination in Switzerland



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Summary

The proliferation of distributed energy resources connected at the medium and low voltage grids is essential to reach the CO_2 targets. Simultaneously, large thermal generators connected at the high voltage level may be decommissioned or only available intermittently. As a result, the traditional source of power system flexibility from conventional generators (ramping up/down, active/reactive power) decreases. In the meantime, the increased stochasticity of intermittent resources such as PVs as well as newly electrified demand such as heat pumps and e-mobility requires the overall system to utilize even more flexible than today.

This project focuses on the new form of flexibility essential for future power system operation: services offered by small distributed energy resources to the TSO (excluding the service to the DSO). The flexibility aggregation is assumed to be performed at the TSO-DSO substation by the distribution utility or an aggregator. We propose an automated estimation approach of the resulting flexibility range. The benefits of utilizing the aggregated flexibility are investigated and demonstrated in the context of Switzerland for ancillary services and transmission system operation. By combining realistic operational data with real grid data, the outcome of this project contributes to the efforts by the TSO and the DSO to achieve a more integrated operational framework.

To assess the benefits of utilizing flexibilities that can be potentially offered by distributed energy resources such as small-scale solar PVs, residential BESSs, residential electric heat pumps and personal EVs in medium- or low-voltage distribution grids, a framework is developed from two perspectives: bottom-up and top-down.

The **bottom-up** perspective involves three aspects. First, we create scenarios and utilization patterns for a representative low voltage grid and identify the availability boundaries of each distributed energy resource. Secondly, we calculate the maximum feasible flexibility that can be offered by each distributed energy resource, aggregated at the transformer station using AC optimal power flow and maximize the “additional” positive/negative active and reactive power exchange at the transformer station around the operating point, while respecting the distribution grid thermal loading and voltage constraints. The result is a time-series of maximum “additional” flexibility in each direction for active and reactive power, constituting a “flexibility region” around an operating point at the transformer station. Lastly, we identify a remuneration scheme for each distributed energy resource, so that the identified “flexibility region” is associated with a cost.

The **top-down** perspective refers to assessing the benefits of utilizing the aggregated flexibilities provided by a large number of distribution grids throughout Switzerland in two case studies. First, for frequency (e.g., secondary) reserves, we formulate a co-optimization problem for the simultaneous dispatch of energy and reserves to quantify the impacts on the generation fleet and system costs when the flexibilities are offered to the reserve market. Secondly, in daily operation, we study how aggregated flexibilities can relieve the required power generation by hydro dams so that the hydro plants are less constrained during the winter months. The problem is formulated as an hourly AC optimal dispatch.

The economic attractiveness and the utilization impact of aggregated flexibilities to provide services to the electricity market through offering their flexible active power capability (positive and negative) as a “capacity reserve” and as a “generator” in Switzerland are demonstrated with a number of scenarios covering different local constraints (e.g., proliferation levels, remuneration amounts, etc.) conditions and different international system conditions. Conclusions present the boundary conditions, and the parameters that influence the potential benefits of utilizing the aggregated flexibilities.

In summary, our take-away messages are as follows: (i) the flexibilities of each distributed energy resource can be aggregated at the transformer station so that the aggregated response can be offered as

a service in TSO markets if a remuneration scheme is in place, and the services respect the distribution grid constraints. The amount of the aggregated response is highly dependent on the layout of the distribution grid, the season, the time of day and the proliferation level of the small distributed energy resources, especially BESSs. (ii) The utilization of the flexibilities as frequency reserves decreases the overall system dispatch cost. The ramping down flexibility offered as downward reserve (provided by charging BESS, increasing conventional demand, turning on HPs, and charging EVs) has the greatest potential because these distributed energy resources together have significant available power during hours when their offer price is below the reserve price. The ramping up flexibility as upward reserve is not often price competitive, given the assumptions. (iii) Utilization of aggregated flexibilities at all load buses throughout the Swiss transmission grid results in more efficient network utilization, subsequently reducing required hydro dam generation requirements (relevant for “winter reserve”), especially following the phase-out of nuclear units and in presence of high shares of solar PV generation.

The overall results address the key areas of TSO-DSO interaction in general, but are particularly relevant for the future development towards an integrated power system operation in Switzerland. Increased TSO-DSO coordination using the approaches developed in this study can mitigate the impact of important current and mid-term challenges, such as the dynamic and stochastic profiles from growing PV and EV capacities across Switzerland, decreasing conventional generation, and potentially reduced transfer capacities from Europe.

Zusammenfassung

Die Verbreitung dezentraler Stromerzeugung in Mittel- und Niederspannungsnetze ist eine wesentliche Voraussetzung für die Erreichung der CO_2-Ziele. Gleichzeitig werden grosse thermische Generatoren, die an die Hochspannungsebene angeschlossen sind, ausser Betrieb genommen oder stehen nur noch zeitweise zur Verfügung. Dies hat zur Folge, dass die traditionelle Flexibilitätsquelle des Stromnetzes durch konventionelle Erzeugung (Hoch- und Herunterfahren von Wirk-/Blindleistung) abnimmt. In der Zwischenzeit erfordert die zunehmende Stochastizität von intermittierenden Erzeugungsanlagen wie PV sowie die neu elektrifizierte Nachfrage durch Wärmepumpen und E-Mobilität, dass das Gesamtsystem noch flexibler als heute genutzt wird.

Dieses Projekt konzentriert sich auf die neue Form der Flexibilität, die für den zukünftigen Betrieb des Stromsystems wesentlich ist: Dienstleistungen, die von dezentralen Energieressourcen dem ÜNB angeboten werden (ausgenommen der Dienstleistung für den lokalen VNB). Es wird davon ausgegangen, dass die Flexibilitätsaggregation an der Schnittstelle zwischen ÜNB und VNB durch den Verteilnetzbetreiber oder einen Aggregator erfolgt. Wir schlagen einen automatisierten Ansatz zur Schätzung des resultierenden Flexibilitätsbereichs vor. Die Vorteile der Nutzung der aggregierten Flexibilität werden im Kontext der Schweiz für Regelenergie und den Betrieb des Übertragungsnetzes untersucht und demonstriert. Durch die Kombination realistischer Betriebsdaten mit realen Netzdaten trägt das Ergebnis dieses Projekts zu den Bemühungen der ÜNB und VNB bei, einen stärker integrierten Betriebsrahmen zu schaffen.

Um die Vorteile der Nutzung von Flexibilitäten zu bewerten, die von dezentralen Energieressourcen wie kleinen PV-Anlagen, BESS für Haushalte, elektrischen Wärmepumpen für Haushalte und privaten E-Fahrzeugen in Mittel- oder Niederspannungsnetzen geboten werden können, wird ein methodischer Rahmen mit zwei Perspektiven entwickelt: Bottom-up und Top-down.

Die "Bottom-up"-Perspektive umfasst drei Aspekte. Zunächst werden Szenarien und Nutzungsmuster für ein repräsentatives Niederspannungsnetz erstellt und die Verfügbarkeitsgrenzen jeder dezentralen Energiequelle ermittelt. Zweitens berechnen wir unter Verwendung eines optimalen AC-Leistungsflusses die maximal mögliche Flexibilität, die von jeder dezentralen Energiequelle angeboten, und an der Schnittstelle aggregiert werden kann. Dabei maximieren wir den “zusätzlichen” positiven/negativen Wirk- und Blindleistungsaustausch an der Schnittstelle um den Betriebspunkt herum, wobei die thermische Belastung und die Spannungsbeschränkungen des Verteilnetzes berücksichtigt werden. Das Ergebnis ist eine Zeitreihe maximaler “zusätzlicher” Flexibilität in jeder Richtung für Wirk- und Blindleistung, die eine “Flexibilitätsregion” um einen Betriebspunkt an der Trafostation darstellt. Schliesslich wird ein Vergütungsschema für jede dezentrale Energiequelle festgelegt, so dass die identifizierte Flexibilitätsregion mit Kosten verbunden ist.

Die Top-Down-Perspektive bezieht sich auf die Bewertung der Vorteile der Nutzung der aggregierten Flexibilitäten, die von einer grossen Anzahl von Verteilnetzen in der Schweiz bereitgestellt werden, in zwei Fallstudien. Erstens formulieren wir für Frequenz- (z.B. Sekundär-) Reserven ein Ko-Optimierungsproblem für den gleichzeitigen Einsatz von Energie und Reserveleistung, um die Auswirkungen auf die Erzeugungund die Systemkosten zu quantifizieren, wenn die Flexibilitäten auf dem Reservemarkt angeboten werden. Zweitens untersuchen wir im täglichen Betrieb, wie die aggregierten Flexibilitäten die erforderliche Stromerzeugung in den Wasserkraftwerken entlasten können, so dass die Wasserkraftwerke in den Wintermonaten weniger stark belastet werden. Das Problem wird als ein stündlicher optimaler AC-Optimaler Leistungsfluss formuliert.

Die wirtschaftliche Attraktivität und die Auswirkungen der Nutzung von aggregierten Flexibilitäten zur Bereitstellung von Dienstleistungen für den Strommarkt durch das Angebot ihrer flexiblen Wirkleistung (positiv und negativ) als “Kapazitätsreserve” und als “Erzeuger” in der Schweiz werden anhand

einer Reihe von Szenarien aufgezeigt, die verschiedene lokale Randbedingungen (z.B. Verbreitungsgrad, Vergütungshöhe usw.) und verschiedene internationale Systembedingungen abdecken. In den Schlussfolgerungen werden die Randbedingungen und die Parameter dargestellt, die den potenziellen Nutzen der Nutzung der aggregierten Flexibilitäten beeinflussen.

Zusammenfassend lassen sich folgende Schlussfolgerungen ziehen: (i) Die Flexibilitäten der einzelnen dezentralen Energieressourcen können an der Schnittstelle zwischen ÜNB und VNB aggregiert werden, so dass sie als Dienstleistung für die ÜNB angeboten werden kann. Vorraussetzung ist das Vorhandensein eines Vergütungssystems und, dass die Dienstleistungen die Beschränkungen des Verteilnetzes respektieren. Der Umfang der aggregierten Flexibilität hängt in hohem Masse von der Auslegung des Verteilnetzes, der Jahreszeit, der Tageszeit und dem Verbreitungsgrad der kleinen dezentralen Energiequellen, insbesondere der BESS, ab. (ii) Die Nutzung der Flexibilitäten als Frequenzreserve senkt die Gesamtkosten des Systembetriebs. Die Abwärtsflexibilität, die als Abwärtsreserve angeboten wird (durch das Aufladen von BESS, die Erhöhung der konventionellen Nachfrage, das Einschalten von Wärmpumpen und das Aufladen von E-Mobilität), hat das grösste Potenzial, da diese dezentralen Energieressourcen zusammen über eine beträchtliche verfügbare Leistung während der Stunden verfügen, in denen ihr Angebotspreis unter dem Reservepreis liegt. Das Hochfahren der Flexibilität als Aufwärtsreserve ist unter den gegebenen Annahmen oft nicht preislich wettbewerbsfähig. (iii) Die Nutzung der aggregierten Flexibilitäten an allen Lastknoten im gesamten Schweizer Übertragungsnetz führt zu einer effizienteren Netzauslastung und damit zu einer Verringerung des Bedarfs an Wasserkraftwerken (relevant für die “Winterreserve”), insbesondere nach dem Ausstieg aus der Kernenergie und bei einem hohen Anteil an solarer PV-Erzeugung.

Résumé

La prolifération des ressources énergétiques distribuées connectées aux réseaux de moyenne et basse tension est essentielle pour atteindre les objectifs en matière de CO2. Simultanément, les grands générateurs thermiques connectés au niveau de la haute tension peuvent être mis hors service ou n'être disponibles que par intermittence. Par conséquence, la source traditionnelle de flexibilité du système électrique provenant des générateurs conventionnels (augmentation / diminution de la puissance, puissance active / réactive) diminue. Dans le même temps, la stochasticité accrue des ressources intermittentes telles que les PV ainsi que la demande nouvellement électrifiée, comme les pompes à chaleur et l'e-mobilité, exigent que le système global soit encore plus flexible qu'aujourd'hui.

Ce projet se concentre sur la nouvelle forme de flexibilité essentielle au fonctionnement du futur système électrique : les services offerts par les petites ressources énergétiques distribuées au GRT (à l'exclusion du service au GRD). L'agrégation de la flexibilité est supposée être effectuée à la sous-station TSO-DSO par la compagnie de distribution ou un agrégateur. Nous proposons une approche d'estimation automatisée de la gamme de flexibilité résultante. Les avantages de l'utilisation de la flexibilité agrégée sont étudiés et démontrés dans le contexte de la Suisse pour les services auxiliaires et l'exploitation du système de transmission. En combinant des données opérationnelles réalistes avec des données de réseau réelles, le résultat de ce projet contribue aux efforts du GRT et du GRD pour atteindre un cadre opérationnel plus intégré.

Pour évaluer les avantages de l'utilisation des flexibilités qui peuvent être potentiellement fournies par les ressources énergétiques distribuées telles que les PV solaires à petite échelle, les BESSs résidentiels, les pompes à chaleur électriques résidentielles et les VEs personnels dans les réseaux de distribution de moyenne ou basse tension, un cadre est développé à partir de deux perspectives : bottom-up et top-down.

La perspective bottom-up comporte trois aspects. Premièrement, nous créons des scénarios et des modèles d'utilisation pour un réseau basse tension représentatif et nous identifions les limites de disponibilité de chaque ressource énergétique distribuée. Deuxièmement, nous calculons la flexibilité maximale réalisable qui peut être offerte par chaque ressource énergétique distribuée, agrégée au poste de transformation en utilisant le flux de puissance optimal CA et en maximisant l'échange de puissance active et réactive positive/négative "supplémentaire" au poste de transformation autour du point de fonctionnement, tout en respectant les contraintes de charge thermique et de tension du réseau de distribution. Le résultat est une série temporelle de flexibilité "additionnelle" maximale dans chaque direction pour la puissance active et réactive, constituant une "région de flexibilité" autour d'un point de fonctionnement au poste de transformation. Enfin, nous identifions un schéma de rémunération pour chaque ressource énergétique distribuée, de sorte que la "région de flexibilité" identifiée soit associée à un coût.

La perspective top-down consiste à évaluer les avantages de l'utilisation des flexibilités agrégées fournies par un grand nombre de réseaux de distribution à travers la Suisse dans deux études de cas. Premièrement, pour les réserves de fréquence (par exemple, secondaires), nous formulons un problème de co-optimisation pour la répartition simultanée de l'énergie et des réserves afin de quantifier les impacts sur le parc de production et les coûts du système lorsque les flexibilités sont offertes au marché des réserves. Deuxièmement, dans le cadre de l'exploitation quotidienne, nous étudions comment les flexibilités agrégées peuvent soulager la production d'énergie requise par les barrages hydroélectriques afin que les centrales hydroélectriques soient moins contraintes pendant les mois d'hiver. Le problème est formulé comme un dispatching optimal horaire en courant alternatif.

L'attractivité économique et l'impact de l'utilisation des flexibilités agrégées pour fournir des services au marché de l'électricité en offrant leur capacité de puissance active flexible (positive et négative)

en tant que " réserve de capacité " et en tant que " générateur " en Suisse sont démontrés à l'aide d'un certain nombre de scénarios couvrant différentes conditions de contraintes locales (par exemple, niveaux de prolifération, montants de rémunération, etc. Les conclusions présentent les conditions limites et les paramètres qui influencent les avantages potentiels de l'utilisation des flexibilités agrégées.

En résumé, nos messages à retenir sont les suivants : (i) les flexibilités de chaque ressource énergétique distribuée peuvent être agrégées au poste de transformation de sorte que la réponse agrégée puisse être offerte comme un service sur les marchés des GRT si un schéma de rémunération est en place, et que les services respectent les contraintes du réseau de distribution. La quantité de la réponse agrégée dépend fortement de la disposition du réseau de distribution, de la saison, de l'heure de la journée et du niveau de prolifération des petites ressources énergétiques distribuées, en particulier les BESS. (ii) L'utilisation des flexibilités comme réserves de fréquence diminue le coût global de répartition du système. La flexibilité de baisse de régime offerte comme réserve descendante (fournie par la charge des BESS, l'augmentation de la demande conventionnelle, la mise en marche des HP et la charge des EV) a le plus grand potentiel parce que ces ressources énergétiques distribuées ont ensemble une puissance disponible importante pendant les heures où leur prix d'offre est inférieur au prix de réserve. La flexibilité de la montée en puissance en tant que réserve ascendante n'est pas souvent compétitive en termes de prix, compte tenu des hypothèses. (iii) L'utilisation des flexibilités agrégées à tous les bus de charge du réseau de transport suisse permet une utilisation plus efficace du réseau, réduisant ainsi les besoins de production des barrages hydroélectriques (pertinents pour la "réserve hivernale"), en particulier après la sortie progressive des unités nucléaires et en présence de parts élevées de production solaire photovoltaïque.

Les résultats globaux portent sur les domaines clés de l'interaction entre les GRT et les GRD en général, mais sont particulièrement pertinents pour le développement futur vers une exploitation intégrée du système électrique en Suisse. Une coordination accrue entre les GRT et les GRD à l'aide des approches développées dans cette étude peut atténuer l'impact d'importants défis actuels et à moyen terme, tels que les profils dynamiques et stochastiques des capacités croissantes de PV et de VE en Suisse, la diminution de la production conventionnelle et la réduction potentielle des capacités de transfert depuis l'Europe.

Contents

Abbreviations

AC	alternating current
AT	Austria
BESS	battery energy storage system
CH	Switzerland
CO_2	carbon dioxide
DC	direct current
DE	Germany
DER	distributed energy resource
DSO	distribution system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EV	electric vehicle
FB	flow-based
FR	France
GTC	grid transfer capacity
HP	heat pump
IEA	International Energy Agency
IT	Italy
NTC	net transfer capacity
OPF	optimal power flow
PV	photovoltaic
RES	renewable energy source
RoR	run of river
SFOE	Swiss Federal Office of Energy
TSO	transmission system operator
TYNDP	ten-year network development plan
VOM	variable operation and maintenance

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1 Introduction

1.1 Project background

As the proliferation of distributed energy resources (DERs) such as residential and utility-scale solar photovoltaics (PVs), battery energy storage systems (BESSs), electric heat pumps (HPs) and electric vehicles (EVs) is increasing, ensuring a secure and reliable operation of the distribution grids requires coordination between the owners of these resources and the system operators or third parties (e.g., aggregators). This coordination often entails real-time interactions (sub-hourly) between the involved parties. The interaction can be facilitated by increased observability of the generation/demand behaviour at the prosumer site, and increased cooperation between the transmission system operators (TSOs) and distribution system operators (DSOs) if DSOs are using only their own assets [1] . The proliferation of smart meters enables for such an observability of the prosumers to be achieved, by telemetering the measurement data to the system operator's EMS SCADA system in high-resolution (sub-hourly) so that the operator can monitor the distribution grid and assess whether the grid security is in jeopardy (e.g., risky loading levels of feeders and transformers, voltage violations).

In the meantime the owners of such DERs can offer services to the grid operators in distribution as well as in transmission by reducing/increasing their withdrawal/injection from/to the grid by adjusting their demand/local generation

- to ensure that the distribution utilities can (i) maintain the grid security and/or (ii) defer asset investment [2],
- to contribute to the system security maintained by the transmission system operators, and/or
- to increase the profitability of their assets by participating in novel local-level markets (e.g., peer-to-peer trading) as well as in existing energy market structures in the transmission level (e.g., balancing).

Such DER services can be referred to as ”flexibility”, which is traditionally defined as the ramping up and ramping down capabilities of the traditional generators that can quickly (e.g., within minutes) increase or decrease their power production on short notice. Due to the decommissioning of such units as a result of future carbon dioxide (CO_2) targets, the overall system will be in need of flexibility services in an increasing manner, which can be provided by non-traditional actors as well, such as DERs. Moreover, the increased stochasticity in the system due to solar PV and newly electrified demand (e.g., HPs, EVs) will contribute to the increasing need for system-level flexibility, as well.

While the HPs and EV charging can easily provide active power flexibility by turning on and off and start/stop charging, respectively, the converter-interfaced units such as BESS and PV can provide both active and reactive power flexibility by adjusting their set-points (injecting/absorbing active/reactive power) thanks to the flexible nature of the converters. Note that conventional demand can also provide flexibility by increasing/decreasing active or reactive power consumption.

Facilitating the utilization of DERs for various services offered to TSOs and DSOs can be performed either directly by sending a communication signal to the individual DER or by establishing a framework such that the flexibilities of DER are aggregated and coordinated by a third party (e.g., aggregator). The location of the aggregation depends on the type and the receiver of the services. If the DSO is the receiver of the flexibility (e.g., to reduce the loading of a cable), the aggregation will need to be performed in a way which will alleviate the loading within the service territory of the DSO. If the TSO is the receiver of the flexibility (e.g., for balancing services), the aggregation will need to be performed at the TSO-DSO substation or at a substation electrically nearby. Such coordinated management of DERs can influence positively the transition to a CO_2-neutral energy system, by increasing the profitability and, therefore, leading to higher proliferation of renewable resources.

It is important to note that the flexibility aggregation has to be formulated in a way that takes into account the constraints of the distribution network and therefore requires the digital representation of the distribution grids (alternating current (AC) model for power flow constraints).

1.2 Project objective

This project focuses on the services offered by small DERs to the TSOs only, and therefore the flexibility aggregation is assumed to be performed at the TSO-DSO substation. It is assumed that there is an established framework to aggregate the flexibility, which can be performed by the distribution utility or an aggregator. The benefits of utilizing the aggregated flexibility are investigated and demonstrated in the context of Switzerland for

- ancillary services
  - *Can aggregated DER flexibility be competitive in ancillary markets day-ahead or intra-day by relying on the flexibility provided by the distributed energy resources so that it is to the benefit of the overall system?*
- transmission system operation
  - *Is it technically and economically feasible for aggregated DER flexibility at the TSO-DSO substation to help line loading and voltage profiles throughout the transmission grid so that it brings benefit to the overall system operation?*

by examining the potential of these interactions using realistic operational data with real grid data, the outcome of this project contributes to the efforts by the TSO and the DSOs to achieve a more integrated operation framework.

1.3 Structure of the report

In order to address the objectives of the project we followed a four-step approach as demonstrated in Figure 1.

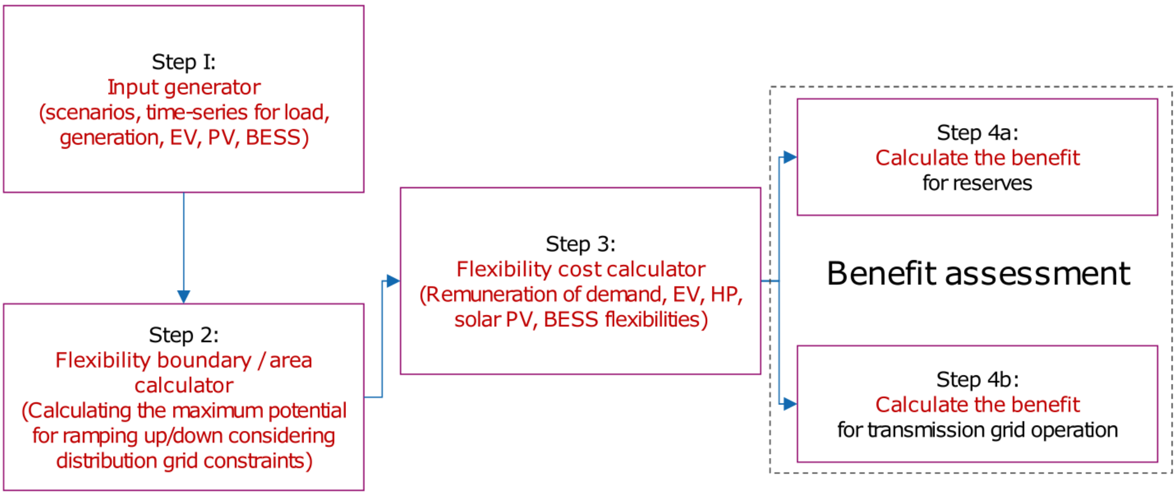


Figure 1: The analysis framework

Step 1 focuses on the input:

- Local level:
    1. Selecting a representative LV network serving a community, based on the LV grids shared by **ewz** and **Repower**
    2. Identifying and creating three (i.e., low, base, high) scenarios for the proliferation of DER (i.e.,solar PV, BESS, electric HP, and EVs), mapped to the selected grid
    3. Creating time-series for each DER for 6 days in 15-minute resolution (i.e., Winter/Summer Saturday/Sunday/Weekday) in each scenario
    4. The flexibility provision limits of each technology
- National level:
    1. European and Swiss scenarios (2050) for electricity generating technologies
    2. Costs of each group of generating technologies
    3. Continental network development plans

Step 2 uses the results of the **Step 1** as input and performs the flexibility aggregation at the TSO-DSO substation. In this step, the **feasible** flexibility boundary at the TSO-DSO substation is calculated for each time-step (96 time-steps) for each day (6 days). Essentially, an optimal power flow, designed to maximize the utilization of flexibilities provided by each DER, is performed around the operating point and for multiple times to sweep four quadrants [in counter-clockwise direction], for each time-step. In short, each quadrant represents how much additional apparent power ΔS step from the operating point at the TSO-DSO substation can be provided thanks to the DER flexibilities. For example, $Q1$ represents the amount of additional active and reactive power that are consumed by the DER by increasing the demand, charging the storage systems, or curtailing the local generation, while $Q3$ represents the amount of additional active and reactive power that can be provided by the DER by reducing the demand, discharging the battery energy storage systems or increasing the local generation.

Step 3 formulates a remuneration framework for the DER so that the flexibility boundaries as well as the contributing DER technologies at each time step obtained in **Step 2** are assigned cost values in terms of CHF/MW, first for every 15-minutes, and then converted to CHF/MWh in a consolidated manner so that we can represent the ”DFlex” units as ”flexibility providing generators” in the upcoming benefit assessment. As a final step, we scale up the available flexibility, assuming that the selected community is representative in Switzerland, so that a meaningful total amount of flexibility can be offered throughout the country.

Finally, in **Step 4**, the results of **Step 3**, the ”flexibility providing generators” at the TSO-DSO substations, are used in two assessments: (i) The system benefit (i.e., total cost of energy) due to DER participation in secondary control market in Switzerland, formulated as a continental co-optimization of energy and reserves in hourly resolution for representative weeks, and (ii) The system benefit in operation, formulated as an optimal power flow problem such that the Swiss hydro generation is reduced on an hourly manner, thanks to the aggregated flexibility during the year so that ”winter reserve” requirements are reduced.

The remainder of the report is structured as follows. Section 2 provides the details of **Step 1**, while Section 3 outlines the framework in **Step 2**. **Step 3** is elaborated upon in Section 2.3, and the benefits in **Step 4** are demonstrated in Section 4 and Section 5, respectively. Note that the results of the *congestion management* and *voltage support* tasks outlined in the proposal are presented in Section 5, while the tasks proposed in the context of *balancing services* are presented in Section 4. Section 6 summarizes the conclusions, while a list of suggested research for the future is listed in Section 7.

2 Scenarios and Flexibilities

In this section, nation-wide and continental energy scenarios for 2050 as well as transmission grid development plans are provided first. These scenarios will serve as the reference for benefit assessment. Next, the methodology for local/district-level proliferation scenarios for distributed energy resources, and the assumptions for the available flexibilities are presented. The activities described in this section constitute **Step 1** in Figure 1.

2.1 Future scenarios for Switzerland and its neighbors

The sections that follow provide details of the data and sources used to model scenarios of the Swiss and neighboring country electricity systems, including the transmission networks (Section 2.1.1), generating capacity developments (Section 2.1.2), and electricity demands (Section 2.1.3). All of these data selections and scenario developments build upon the work done in the Nexus-e project [3].

2.1.1 Transmission network

As part of this work, the grid operation analysis (Section 5) includes a detailed representation of the Switzerland (CH) transmission grid and an aggregated representation of the transmission grid of the four neighboring countries - Germany (DE), France (FR), Italy (IT), and Austria (AT), with data from Swissgrid [4] and the European Network of Transmission System Operators for Electricity (ENTSO-E) [5, 6]. Figure 2 shows the 2025 transmission grid (includes planned line upgrades until 2025). We use this representation to simulate the scenario-years 2030, 2040, and 2050. In total, the 2025 model comprises 173 nodes, 281 lines and 25 transformers.

To model the connection with the neighboring countries, we aggregate the detailed ENTSO-E network data using a network reduction method, which was developed as part of previous works [7]. Since we aggregate the surrounding regions' networks to have single connections between countries, it is necessary to create aggregate physical parameters that allow accurate representation of how power injections split and flow between the countries. The network reduction process determines optimal line reactances for this purpose. In the resulting reduced representation, all Swiss cross-border lines going to a neighboring country connect to a single border node, which further connects to the main node of that country through an aggregated line. The neighboring countries are also connected to each other with a single aggregated line. The generator capacities of each neighboring country are placed at the main country node (not at the border node). No modification of the Swiss transmission network parameters is necessary since we represent all these network components in detail and know their physical data from Swissgrid (2025 data [4, 8]).

The line limits of the aggregated lines between Switzerland and the neighboring countries are modified to have transfer capacities that reflect the market-based limits (i.e., net transfer capacity (NTC) or flow-based (FB) limit). Analogously, the aggregated lines connecting the neighboring countries also use modified limits to reflect the market-based transfer capacities. We gathered the data for these limits on market-based transfer capacities from Swissgrid [9] and recent ENTSO-E studies [10, 11].

The system reserve analysis (Section 4) uses the same fully detailed ENTSO-E network data [5] and network reduction method [7] to create an aggregated model of the five countries. In this version, each country is represented by a single node with aggregated line connections to each neighboring country. Since the procurement of reserve capacities within Switzerland is not location-specific, the aggregation of the Swiss network allows for an accurate economic assessment of the ability for generators

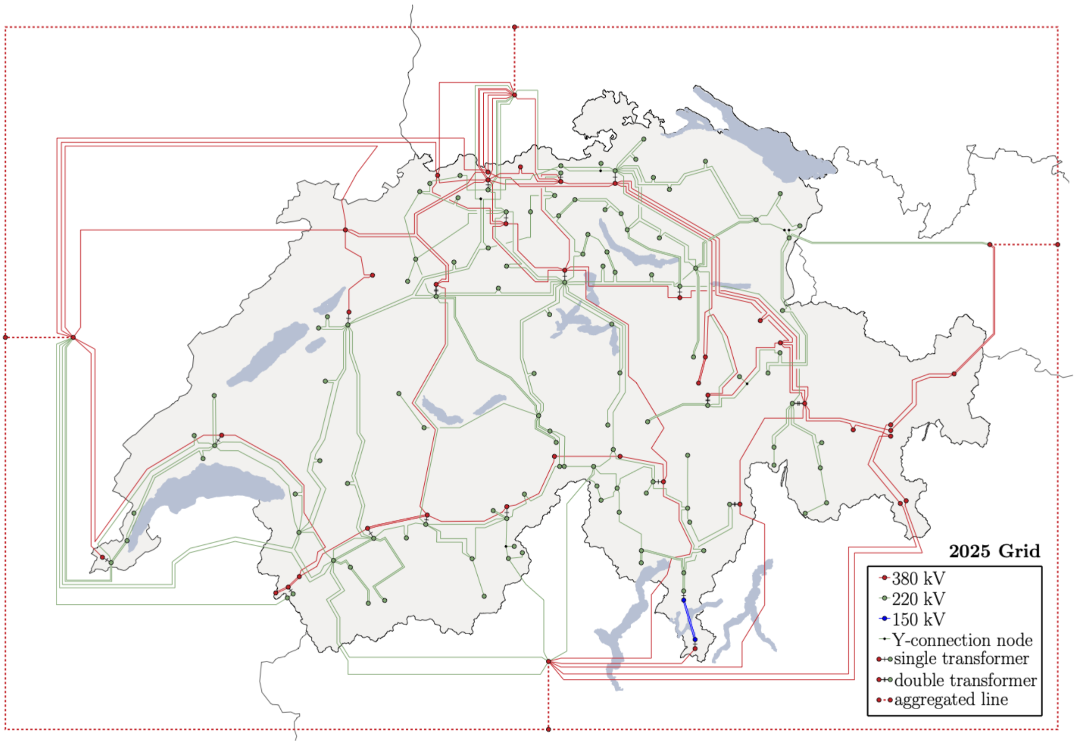


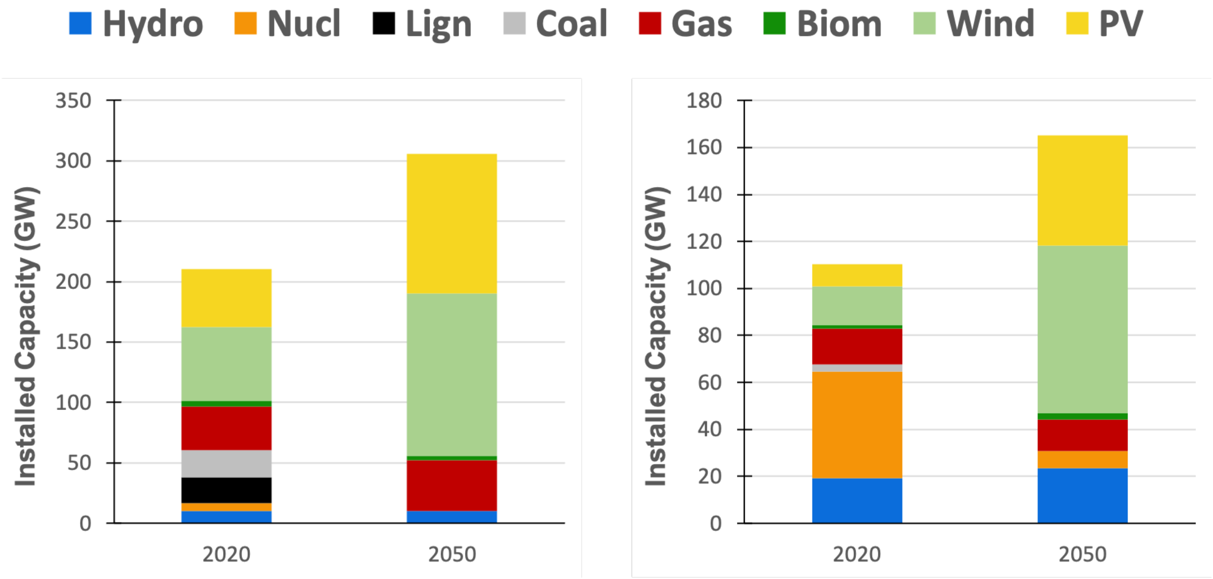
Figure 2: The 2025 transmission grid is modeled to represent the network of Switzerland (in detail) and its four neighboring countries (aggregated).

to compete for procurement of reserves while reducing the computational complexity of the simulation. As will be discussed in Section 4, various scenarios will be used to limit the aggregated line capacities connecting the five countries, including: allowing the full grid transfer capacity (GTC) limits, allowing the market-based NTC limits as projected by ENTSO-E [10, 11], and allowing only one-third of the market NTC limits.

2.1.2 Generating capacity developments

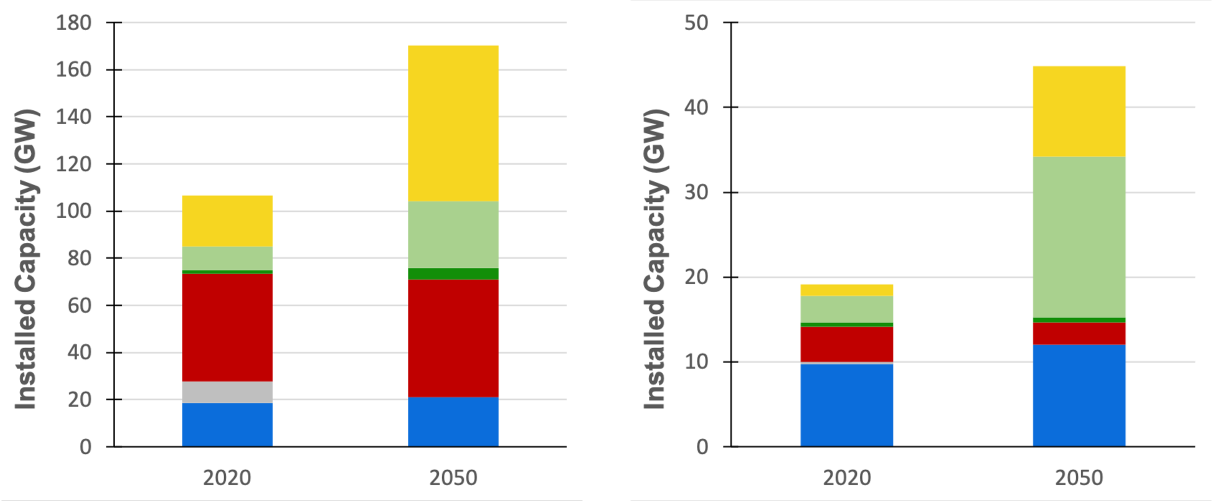
All generators in the neighboring European Union (EU) countries are aggregated to one unit per technology type. Much of the data needed to represent these EU generator capacities in a given future year are adopted from the Global Ambition scenario of the recent ENTSO-E ten-year network development plan (TYNDP) 2020 study [12]. Figure 3 illustrates the development of installed capacities between 2020-2050 for the countries neighboring Switzerland. In addition to the generator capacities, the annual production of wind and PV in the neighboring countries, also taken from the TYNDP [12], are used to scale the hourly production profiles.

For existing Swiss generator capacities and locations, we use data from the Swiss Federal Office of Energy (SFOE) [13, 14, 15, 16] and previous studies [17]. The generating capacities represent those existing in 2020, which we assume also remain in place until 2050, along with added biomass units to represent new waste-fired generators and removal of all Swiss nuclear generators. Figure 4 illustrates the development of installed capacities between 2020-2050 for Switzerland. In addition to the existing capacities, additional inputs are needed for projections of wind and PV generator capacities as well as their hourly production profiles. These additional inputs rely heavily on data available from previous



(a) Germany

(b) France



(c) Italy

(d) Austria

Figure 3: Generating capacity developments in Europe. 2020 data shown were taken from the ENTSO-E TYNDP 2020 study [12]

works as part of the AFEM (Assessing Future Electricity Markets) project [17] that included detailed assessments of the renewable energy source (RES) potentials and generation profiles. The production profiles of wind and PV are then scaled to achieve the annual total generation projected in the ZERO-Basis scenario of the recent Swiss Energieperspektiven 2050+ report [18].

To represent the variable operating costs and fuel costs of all Swiss generators (existing and new) we use data from recent SFOE sponsored studies [19, 20]. The costs of biomass reflect current waste incineration subsidies, which we expect to continue in the future. The variable operation and maintenance (VOM) cost for each technology type is assumed to stay the same in any 2020-2050 scenario-year; however, the fuel and CO_2 portions of the total variable operating cost will change based on the assumed trajectories for the prices of each fuel and the price of CO_2 in future years. To represent the variable

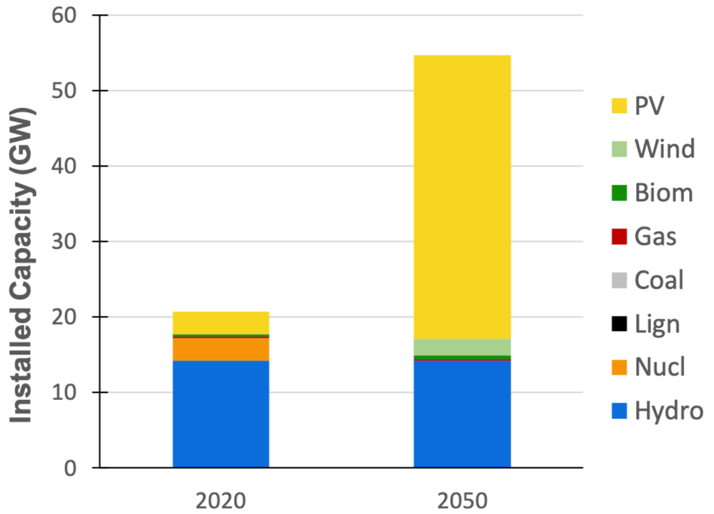


Figure 4: Generating capacity developments in Switzerland.

operating costs of all EU generators, we use data from the comprehensive 2020 report published by the International Energy Agency (IEA) [21]. Note that, several VOM costs were adjusted as part of a calibration process performed as part of a separate study. In an effort to maintain data consistency, the fuel prices for all EU generators were taken from the ENTSO-E TYNDP 2020 study [12]. The VOM cost for each technology type is assumed to stay the same in any 2020-2050 scenario-year; however, the fuel and CO_2 portions of the total variable operating cost will change based on the assumed trajectories for the prices of each fuel and the price of CO_2 in future years. Additionally, all generators in all countries must pay for any CO_2 emissions, using a price based on the ENTSO-E TYNDP 2020 study [12]. In all years, the prices assumed for CO_2 are the same in Switzerland and in the neighboring countries. Tables 1 and 2 present the VOM and fuel/CO_2 price utilized to simulate 2050 in this work.

Table 1: VOM cost parameters (EUR/MWh) for Swiss and European generators in 2050.

Technology Type	**CH VOM Cost**	**EU VOM Cost**
Hydro Dam	10.00	15.00
Hydro Pump	8.18	6.67
Hydro RoR	9.09	7.08
Nuclear	-	10.83
Gas CC	2.00	5.00
Gas SC	11.00	8.33
Biomass	1.00	11.67
Oil	80.00	80.00
Wind Onshore	36.36	12.92
Wind Offshore	-	18.75
PV	27.27	17.92

Table 2: The fuel prices (EUR/MWh$_{th}$) and CO_2 price (EUR/ton) for Swiss and European generators in 2050.

Fuel	CH	EU
Gas	54.64	27.76
Oil	65.63	86.04
Biomass	0.00	17.45
Uranium	-	1.69
CO_2	166	166

2.1.3 Electricity demand

To represent the electricity demand of Switzerland and the neighboring EU countries, we utilize available data for the 2018 hourly profiles of demand for each country and for the 2020-2050 annual total demand in a given year for each country. For Switzerland, the 2018 profile of the hourly electricity demand is available from Swissgrid [22]; while for the hourly profile of neighboring countries, we use 2018 data available from ENTSO-E [23]. In any 2020-2050 scenario-year, these profiles are scaled to ensure that the annual electricity demand for each country matches the desired totals for any scenario-year. The Swiss annual electricity demand values for any 2020-2050 scenario-year is taken from the ZERO-Basis scenario of the recent SFOE-sponsored Energieperspektiven 2050+ report [18]. While the annual electricity demand for the neighboring EU countries for 2020-2050 are taken from the Global Ambition scenario of the recent ENTSO-E TYNDP 2020 report [12].

2.2 Local/district grid, scenarios and flexibilities

In this section, the framework of setting up a representative grid serving a district, with DERs such as solar PV generation, electric HPs, BESSs, EVs is summarized. The aim is (i) to identify an LV grid, (ii) to assign population and DER to each node for selected proliferation scenarios, and (iii) to create time-series for each DER. Note that the approximation is not performed at the building level but at the node of the selected grid. The resulting time-series for each node will be later used in Section 3 to calculate aggregated flexibilities at the TSO-DSO substation.

Multiple LV grids are provided by **ewz** and **Repower** for analysis. These grids and the relevant data represented only one time snapshot for load (without a time stamp), and they contain transformer and cable/line parameters as well as ratings. The provided grids are analyzed under different loading conditions for different scenarios of DER proliferation and one of them is selected as a representative network.

Since, realistic representation of nodal demand and proliferation of DER is required for the analysis, a scenario and time-series generator is designed which approximately determines the population living in the territory serviced by the LV grid, and finally creates time-series of conventional demand, EV charging, electric HP consumption, solar PV generation and BESS charging/discharging profiles in 15-minute resolution for representative weekdays, Saturdays and Sundays for three seasons: Winter, Summer and Spring/Fall, a total of 9 days for each season for each scenario. The steps and assumptions in creating these time-series is as follows:

Conventional demand: The transformer rating,$P^{trafo}_{capacity}$ is used to determine the annual energy supplied by the transformer, E^{trafo}_{annual}. A median loading, α, of 20% on an annual basis is used, as it is a reasonable assumption in Switzerland. The annual total demand supplied by the transformer is determined by:

$$E_{annual}^{trafo} = P_{capacity}^{trafo} \cdot \alpha \cdot 8760 \tag{1}$$

Roughly 65% of the total annual demand is assumed to be the household customers (H4: : 4’500 kWh/year consumption, ElCom), while the rest of the demand is assumed to be a mixture of small commercial customers (C1 & C2:8’000 & 30’000 kWh/year consumption, ElCom). This ratio is kept constant for each node of the LV grid. Using the assumed ratio, the total annual electric consumption of the households, $E_{annual}^{households}$, supplied by the LV grid is obtained. Using an annual demand per person, E_{annual}^{person}, of 2.5 MWh per person (i.e., total household electricity consumption divided by the population), the approximate number of people living in the district is determined as follows.

$$N_{people}^{district} = E_{annual}^{households} / E_{annual}^{person} \tag{2}$$

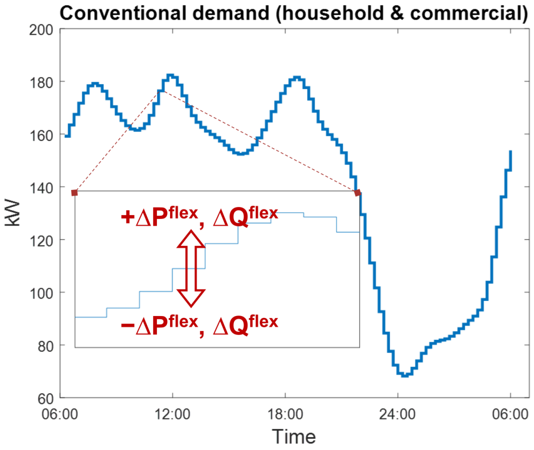


Figure 5: Conventional demand flexibilities

In the meantime, using the demand distribution of each node in the provided snapshot of the LV grid, each node is assigned an annual household consumption, an annual commercial consumption as well as number of people. The approximate number of cars, N_{auto}^{node}, at each node is calculated by using a car ownership ratio of 0.542 (Federal Statistical Office). Standard averaged household and commercial demand profiles provided in 15-minute time resolution for an annual consumption of 1’000 kWh (VDEW 1999) are used to scale up and assign the conventional load time series to each node. The power factors of the provided snapshot at each node is used to determine the reactive power consumption time-series at each node. A random temporal shifting is applied to the demand time-series at each node to achieve a simultaneity factor of 30%, typical in Switzerland. It is assumed that each demand group (household & commercial) can provide 10% ramping up and ramping down capability, however, we assume that the household customers do not provide reactive power capability while the commercial customers can. Figure 5 demonstrates the flexibility concept at a time instant on one day at one node. The conventional demand is assumed to be the same in the selected district in the various scenarios considered in this study.

EV charging: Since the number of personal vehicles, N_{auto}^{node}, is already estimated for the district, the share of EVs is treated as a scenario parameter. For a selected scenario, the number of EVs, N_{EV}^{node}, is calculated and an average rating for the charging infrastructure is assigned to each node. It is assumed that each EV has access to a charging station at the time of its arrival or at the time when it starts charging. In order to estimate and randomize the daily distances, driven by each EV, official statistics for average daily distance driven by personal vehicles, $\bar{\mu}_{km}^{daily}$, are used (Federal Statistical Office), which distinguish between the weekend and the week day mobilities, as well as between winter and summer seasons. In order to be able to create a realistic distances for each EV while ensuring that different types of EV utilization patterns are covered, we used Gaussian distribution with a selected standard deviation for average daily driven distance, σ_{km}^{daily} , as well as for average charging starting times,$\sigma_{t}^{charging}$, such that 95% of the sample data is within $\bar{\mu} \pm 2\sigma$. It is assumed that the EVs charge in the evening all of the amount of energy that they spent during the day. The average EV efficiency, η_{EV} in *kWh*/*km*, is treated as a scenario parameter, and ”decreases” (i.e., EVs become more efficient, consuming less kWh per km driven) according to the projections in each future scenario. The time-series for EV charging is created in 15-minute resolution.

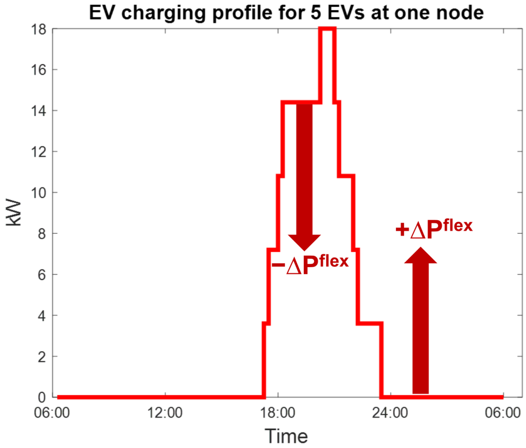


Figure 6: EV Charging flexibilities

It is assumed that the EV owners can provide flexibility by communicating an ”availability signal”, based on their desire of when their EVs are available for charging. The availability signal is proposed to be a binary signal (e.g., 1-available- between 19:00 and 05:00, and 0-unavailable- otherwise), which can be communicated or be accessible at the measurement point at the EV location via a home energy management system, in a pre-determined time-resolution (e.g., 15 minutes), for the next day or for the next *x* hours within the day (intra-day), if the flexibility offering is performed in an *x-hour-ahead* framework, requiring the availability signal changing in a sliding-mode manner. ”Availability signal” concept, proposed in this study, is essentially a ”traffic light”, which will be determined by the EV (or any other DER) owner. This method ensures that the EV owners can modify the availability of the EVs according to their projected needs, but have to comply with the availability signal which is valid for a pre-determined time duration (e.g., x hours or one day or one week). In the meantime, the ”availability signal” concept ensures that the DER owners prevent the potential ”over- utilization” of the DER technology. Figure 6 demonstrates the EV flexibility concept. Note that the amount of additional flexibility that can be provided by the EV (or any other DER) in the figure is determined as a result of the optimization process which will be described in Section 3.

Following is the summary of the assumptions used to formulate the EV flexibilities in the optimization process for flexibility aggregation:

- The provided flexibility is reducing or increasing the charging.
- Slow charging (not charging at full power) is allowed.
- Availability of EV is known via an availability signal provided by the owner.
- Continuous ramping down of charging is allowed.
- Vehicle to grid discharging is *not* allowed.

HP: In order to estimate the required heat demand per node, we assume that the average floor area (to be heated) per person is a Swiss average, $50m^2$. We assume an average heat demand per m^2 per annum equal to $90kWh/(m^2 \cdot year)$, and an average coefficient of performance for the air-water electric heat pumps as 3.0 to derive a standard operation profile (per person and per floor area) for the HP based on the analysis of a measured time-series of a heat-pump, provided by **ewz**. Since we assigned the number of people to each node, we created the HP time-series, in 15-minute resolution, for each node by first scaling the standard profile by using the number of people per node and then by randomly shifting the time-series $\pm 1 hour$, using uniform distribution, so that the simultaneity factor is respected, and unrealistic power consumption peaks are avoided. The share of the HPs is treated as a scenario parameter and it is applied to the total floor area to be heated per node.

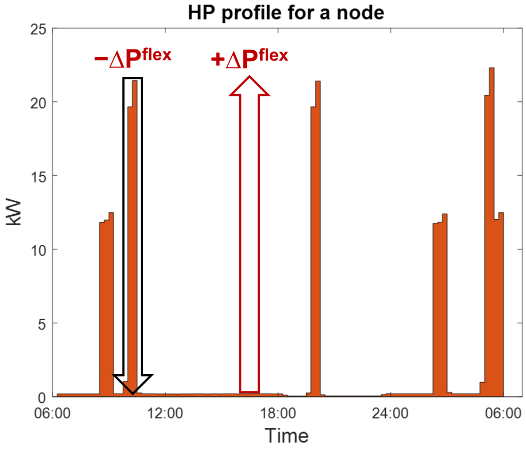


Figure 7: HP flexibilities

Similar to the concept for EV, we assume that the owners of HPs use an ”availability signal”, which they can update according to the duration of the flexibility framework as explained above for EV. The flexibility concept for HPs is demonstrated in Figure 7, based on the assumption that HPs can provide continuous ramping up and down (i.e., turning on/off, increasing/decreasing consumption). Presently, the standards and the technology available in the market do not allow such operation; however, in the future HPs may be equipped with such flexibility in their operation (e.g., Smart Grid Ready) and therefore we wanted to observe how exploitation of such operation can increase the flexibility offering.

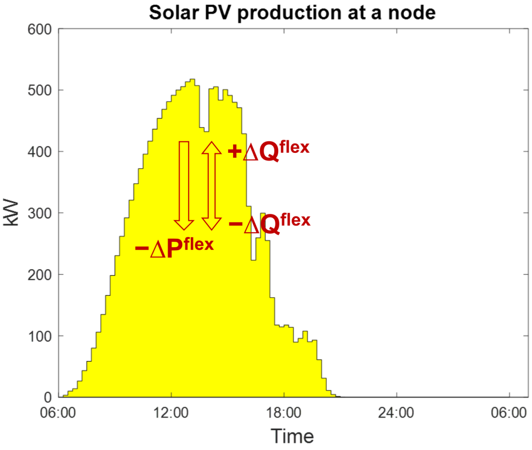


Figure 8: Solar PV flexibilities

Solar PV: The size of the installed solar PV is determined by using the total annual household demand, $E^{household}_{annual}$, and the annual generation from 1 kWp installed solar PV, $900kWh/kWp$ for Switzerland. The share of the PV is used as a scenario parameter and finally the kWp installed capacity of

PV is determined per node. We derived a standard time-series for solar PV, based on the measured time-series of an aggregated solar PV generation, provided by **ewz**, which is then scaled by using the installed capacity at each node, in 15-minute resolution. It is assumed that the solar PV converter is not oversized.

$$P^{PV}_{kWp} = E^{household}_{annual} \cdot PV_{share}/(900kWh/kWp) \tag{3}$$

It is assumed that the solar PV owners are allowed to curtail the generation to provide flexibility, which corresponds to increasing demand. Since curtailment is generally not favored, we assume that it is limited to 10% of the available solar PV generation. Figure 8 demonstrates the flexibility concept for solar PV generation. The flexibility is assumed to be provided following a V-shaped PQ capability curve, adjusted for a power factor, 0.95.

BESS charging/discharging: The excess energy due to solar PV production not consumed locally, resulting in reverse flows and overvoltages in grids with high shares of PVs, can be mitigated by residential BESS, which significantly increase the self-consumption and self-sufficiency of the prosumers, especially when feed-in tariffs (or other solar remuneration schemes) are not attractive. The overall controllability of residential PV systems is expected to increase if they are coupled with BESS at the household level. As a by-product, PV+BESS introduce more flexibility which can be further exploited in peak shaving, load leveling, demand response, voltage regulation, and other ancillary services. Therefore, the proliferation of BESS by PV owners is expected to increase, especially with decreasing capital costs and increasing governmental subsidies.

In this study it is assumed that only PV owners install BESS. The installed energy capacity of BESS is determined by using the annual generation of the installed solar PV, E^{PV}_{annual}. We assume that the BESSs are designed to store 50% of the solar PV generation on average and on a daily basis. The share of the BESS is used as a scenario parameter. Once the installed energy capacity for BESS, E^{BESS}_{kWh} per node is determined, the converter capacity for BESS, P^{BESS}_{kW}, is selected. Based on our analysis of available BESS in the market (Varta, Sonnenbatterie, Tesla), we assume that the smallest E^{BESS}_{kWh} is $3kWh$ while the smallest P^{BESS}_{kW} is $2kW$. The BESSs larger than $3kWh$ but smaller than $10kWh$ are assumed to be equipped with a converter size, $P^{BESS}_{kW} = 3kW$, and those larger than $10kWh$ but smaller than $30kWh$ are assumed to be equipped with $P^{BESS}_{kW} = 5kW$. We assume that the average energy and converter capacity of the installed BESS is $10kWh$ and $5kW$, respectively.

$$E^{BESS}_{kWh} = 0.5 \cdot E^{PV}_{annual} \cdot BESS_{share}/365 \tag{4}$$

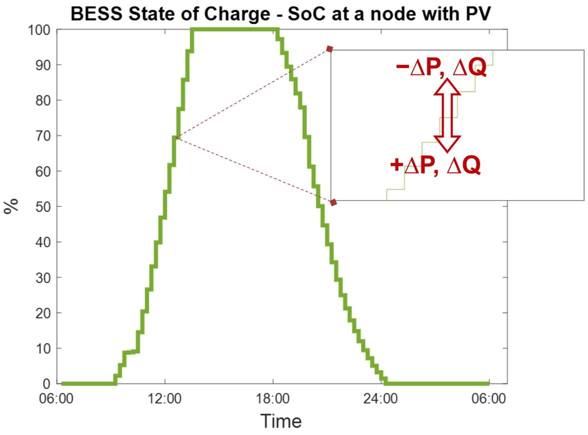


Figure 9: BESS flexibilities

We implemented two different strategies for BESS charging and discharging: (i) *Grid-independent*: BESS starts charging when there is excess solar PV generation and it starts discharging when there is no excess solar PV, and (ii) *Grid-friendly*: BESS starts charging 1.5*hour* before the projected maximum excess solar, and it starts discharging 1.5*hour* before the projected maximum net demand. Note that it is assumed that BESS owners cannot engage with arbitrage strategies, and BESS is charged only when there is excess solar PV generation. Figure 9 demonstrates the BESS flexibility concept and it is assumed that BESS can provide ramping up flexibility by discharging and ramping down flexibility by charging at the operating point. The BESS active and reactive power capability is driven by the converter characteristics, which, based on our assumption, are equipped with four-quadrant capability. Note that, [24] reported recently that the reactive power injection capability of BESS are non-linearly dependent on the AC voltage at the point of connection as well as the DC voltage of the capacitor in the BESS. This dependence can significantly influence the reactive power flexibility provided by BESS. Therefore, we applied a *loss factor* to the reactive power provision (i.e. only when injecting reactive power to the grid) capability of the BESS of 50% to account for this limitation.

Table 3: Scenario parameters

Scenarios	Low	Medium	High
Solar PV	30%	70%	120%
HP	10%	20%	30%
BESS	30%	50%	70%
EV	10%	30%	50%
EV efficiency [kWh/100] km	25	20	15
Average charging capacity [kW]	3.6	3.6	7.2

Table 4: Installed capacities per scenario

Installed total capacities [MW]	Low	Medium	High
Solar PV	0.61	1.40	2.39
HP	0.10	0.19	0.28
BESS [MW / MWh]	0.09 / 0.24	0.42 / 0.88	1.03 / 2.08
EV total charging capacity	0.11	0.19	0.53

The scenario parameters used to create the time-series for each DER is provided in Table 3. Note that the estimated number of people in the selected representative district is 729, served by 39 nodes and 44 branches, with the MV-LV transformer rated at 1.2 MVA. The maximum demand is not expected to exceed 0.5 MW ($\sim$ 40% of transformer loading. The 120% solar PV proliferation results in $2.4 MWp$ total installed capacity, which corresponds to $\sim 3.3 kWp/person$ in the district. This value can be compared to $\sim 3.7 kWp/person$ installed PV target in Switzerland based on the SFOE EP2050 Zero Basis scenario for solar PV installed capacity of $37.5 GWp$ and the projected Swiss population of 10.3M. In the meantime, the 70% BESS proliferation corresponds to 25 BESSs in total resulting in a $1 MW$ total converter capacity and a $\sim 2 MWh$ of energy capacity, while total EV charging capacity is $\sim 0.5 MW$, serving a total number of 74 EVs, assumed to be owned by the residents. Finally, 30% of HP proliferation in ”high” scenario corresponds to a total of $\sim 0.3 MW$ installed HP capacity as shown in Table4.

2.3 Flexibility remuneration

In order for the DER owners to provide additional flexibility to the system, they have to be remunerated to compensate for the loss of opportunity. As an example, when the BESS owner cannot decrease the local consumption by discharging stored energy in the evening because the BESS is already committed to provide a service by discharging its energy resulting in an increase in the electricity bill which is defined as loss of opportunity. In this project we calculate the remuneration for each DER which is the least amount that the DER owners would accept to provide ramping up (acting like generator, discharging

BESS, or increasing demand) and ramping down (acting like demand, curtailing solar, charging BESS) flexibilities. We assume that the minimum cost of flexibility service provided by the DERs shall be the remuneration we will explain in this section. This way, the DER owner is guaranteed that there is no financial risk in providing flexibility. Even though investigation of appropriate options for a flexibility market framework is not within the scope of this work, we can safely argue that when the flexibility provision by DER benefits the system such that total cost of supplying energy reduces or the security level of the overall system is increased, the DER owners can be awarded in relation to the benefit they brought to the system in addition to the ”minimum” remuneration they received. Thanks to such cases, DER profitability will increase, will subsequently motivate higher adoption of these technologies.

The remuneration of ramping down (i.e., from system perspective a generator reduces its generation) which corresponds to increasing demand (i.e., conventional demand, HP, EV, BESS charging) or decreasing generation is assumed in this study to be dependent on the retail tariff and the feed-in tariff structures. The retail tariff in the future can still have a 2-tier structure as today (low tariff, high tariff), it might have more tiers, as well as be dynamic (i.e., changing every day once, or multiple times a day, etc.). We assume that independent of the retail tariff structure, the DER owner will be remunerated based on the difference between the tariff at the time of flexibility provision and the minimum tariff, $\Delta Tariff$. If it is a 2-tier retail tariff structure, $\Delta Tariff = HT - LT$, where HT stands for high-tariff and LT stands for the low-tariff. In the mean time, the solar curtailment is assumed to be remunerated by using the feed-in tariff structure, which can be based on a constant amount, or it might be dynamic based on the market value of the solar generation at the projected time of flexibility provision.

The remuneration of ramping up (i.e., from system perspective a generator increases its production), which corresponds to decreasing demand or increasing local generation (i.e., BESS discharging) is assumed to be only dependent on the retail tariff structure. We assume that the DER owner will be remunerated with respect to the difference between the tariff at the time of flexibility provision and the minimum tariff, $\Delta Tariff$ as it is the case for the flexibility remuneration for ramping down. As stated before, we assume that BESSs start discharging in the evening times when the demand is significantly high. If the BESS provides flexibility by discharging its energy during the day, the BESS owner will have to pay most likely the low tariff for the energy required in the evening. Therefore, the BESS discharging will be remunerated by using the minimum tariff (low tariff if there is 2-level tariff structure) during the day instead of the $DeltaTariff$.

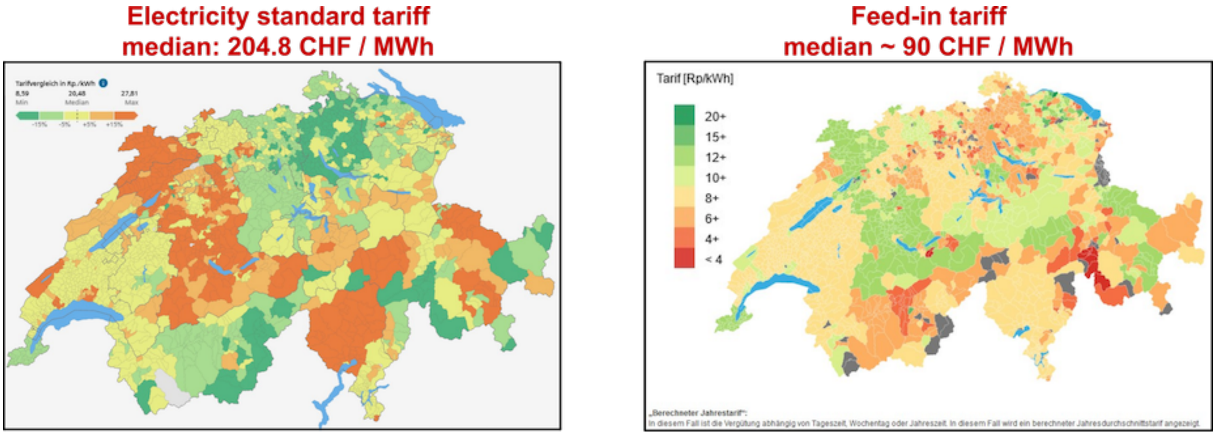


Figure 10: Retail (ElCom) and feed-in tariffs in Switzerland (VESE)

As Figures 10 and 11 demonstrate, Switzerland does not have a uniform tariff structure throughout the country, neither for retail nor for feed-in. For example, the high tariff for average household customers in Switzerland can be as high as $28 Rp/kWh$ ($280 CHF/MWh$) with a median value of $\sim 20 Rp/kWh$ ($200 CHF/MWh$) and low tariffs can be as low as $11 Rp/kWh$ ($110 CHF/MWh$) with a median value of $19.7 Rp/kWh$ ($197 CHF/MWh$) (ElCom 2020). Therefore, we took into account different levels of $\Delta Tariff$

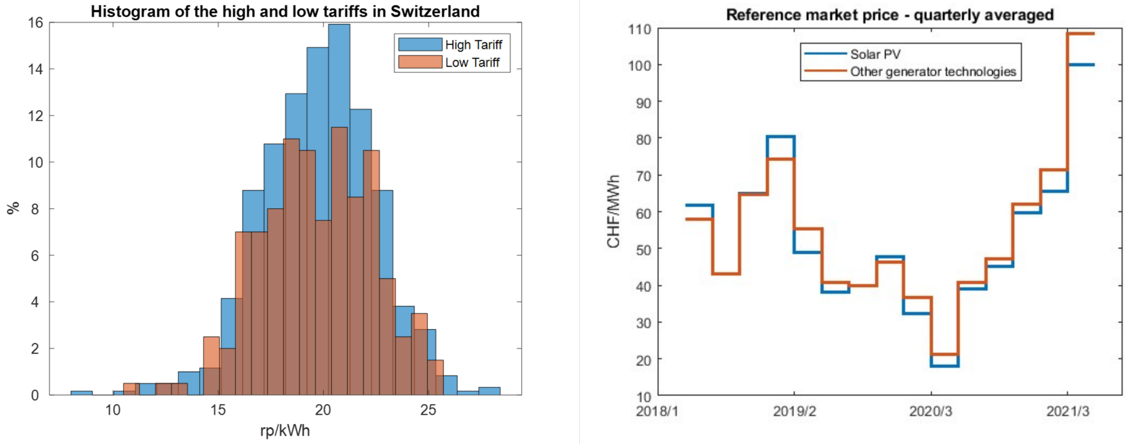


Figure 11: Left: High and low tariffs (ElCom) in Switzerland, Right: reference market price for PV (SFOE)

for flexibility remuneration, since it drastically impacts the competitiveness of DER flexibility provision. In the meantime, the feed-in tariffs can be as high as $200 CHF/MWh$, and as low as $30 CHF/MWh$ with a median of $\sim 90 CHF/MWh$. Since the remuneration of solar curtailment is assumed to be proportional with the feed-in (or market price) and it highly influences the competitiveness of solar flexibility, we analyzed different level of feed-in tariffs.

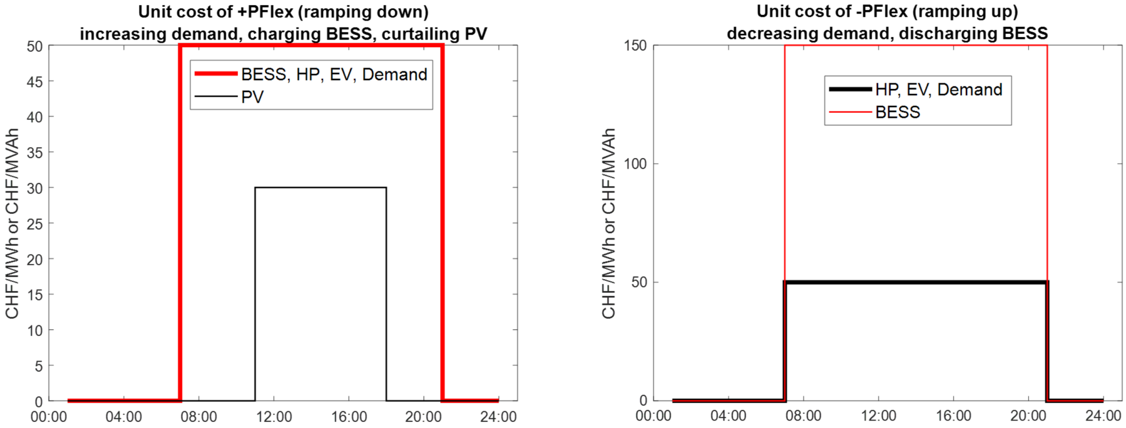


Figure 12: Unit costs of providing + flexibility (increasing demand, charging BESS, curtailing solar PV: ramping down for the system) and - flexibility (decreasing demand, discharging BESS: ramping up for the system).

Figure 12 demonstrates the concept used in this project based on an example, where the feed-in (or market price) for solar PV is $30 CHF/MWh$, the low-tariff in a 2-tier structure is $150 CHF/MWh$ and the high-tariff is $200 CHF/MWh$. It is assumed that the high-tariff starts at 06:00 and ends at 20:00, while the excess solar PV is observed between 10:00 and 17:00. As explained, the positive (+) flexibility provided by charging BESS, turning up/on HP, starting EV charging or increasing conventional demand is driven by the difference between the current retail tariff and the low retail tariff, $\Delta Tariff$, and therefore between 20:00 and 06:00, it is practically free under our assumptions, which is optimistic. Providing (+) flexibility by increasing demand between 06:00 and 20:00 is remunerated at $50 CHF/MWh$, while if solar curtailment is used during the excess hours, the flexibility will have to be remunerated at an additional $30 CHF/MWh$. The cost of providing negative (-) flexibility by turning down/off HP, slowing or stopping EV charging or decreasing conventional demand is driven by $\Delta Tariff$, while providing (-) flexibility by discharging BESS is driven by the low-tariff, $150 CHF/MWh$ (or the lowest tariff of the day) as explained.

It is noted that the reactive power flexibility provided by solar PV and BESS is achieved at the expense of utilizing active power. Therefore, the price of reactive power flexibility provided by these sources follows the same rules as described above leading to the same unit costs. Therefore, the price of the reactive power flexibility that can be provided by the DERs are high under our assumptions, when compared to the Swissgrid tariff for reactive energy for semi-active participants (distribution system operators in the transmission system) or for active participants non-compliant with requirements (distribution system operators and power plants in the transmission system), $1.64 Rp/kVarh$ ($16.4 CHF/MVArh$).

3 Flexibility aggregation

Proliferation of DERs connected at the medium voltage (MV) and low voltage (LV) grids is inevitable to reach the CO_2 targets, while large thermal generators connected at the high voltage (HV) will be decommissioned or frequently switched off. Therefore, the number of conventional generators providing flexibility (ramping up/down, active/reactive power) to the system decreases. In the meantime, the increased stochasticity due to the intermittent resources such as PVs as well as the newly electrified demand such as heat pumps and e-mobility requires the overall system even more flexible than today [25].

Utilization of the flexibility from DERs located in distribution grids has been studied from different perspectives [26, 27]:

- the type of flexibility services [fast/slow],
- the receiver of the services: the TSOs (e.g., frequency control, congestion management, voltage control) from distribution system operator (DSO) [28, 29, 30] or the DSOs (e.g., congestion management, voltage control to defer asset investment),
- the type of markets or contracts that are necessary to enable the utilization of the distributed flexibility (e.g., participation of DER in wholesale markets, local markets, etc,) [31, 32, 33, 34],
- the regulatory requirements,
- the required information and communication technology (ICT) infrastructure, and the associated reliability requirements and cost of such infrastructure [installation if it does not exist, utilization if it exists],
- technical methodologies to directly utilize or aggregate the flexibility services that can be provided by these resources.

The focus of this section is to present the methodology to perform the flexibility aggregation at the TSO-DSO substation to compute the aggregated flexibility potential of all DERs such as small-scale renewables (e.g., solar PV) or conventional generation (e.g., biogas, geothermal), small- or utility-scale BESS, and electrified demand (e.g., electric HPs, EV charging) in a distribution network.

Such aggregation of the flexibility of each DER can then be potentially scheduled week-ahead, day-ahead or intra-day (i.e., x-hour-ahead), to provide services (by the DERs) to the TSOs only (e.g., balancing, congestion management, voltage support).

Note that ”flexibility” is used to represent how much a DER can increase or decrease its consumption/generation at the operating point of a given instant. An operating point for the DER denotes the setpoint of the device (how much energy it consumes or generates) at a given time, while an operating point for the system represents the state of the distribution grid at a given time, determining a steady-sate instant when the generation-demand is balanced, all the line loadings and the nodal voltages are within limits, either TSO is supplying energy to the DSO or the DSO is self-sufficient. For example, if a BESS, with $3kW$ converter and $10kWh$ energy capacity, and 50% state of charge at a given time, is charging at $2kW$, it has a flexibility of changing its setpoint by increasing the charging for another $1kW$ at that time or discharging $3kW$ (by stopping charging and discharging its energy). Similarly, if a solar PV is generating $10kW$, and provides 10% flexibility, it can curtail $1kW$ as flexibility, changing its setpoint. Aggregation of the flexibilities of each DER in a given network is performed at the TSO-DSO substation, and essentially identifies how much more power can flow from TSO to DSO or from DSO to TSO at a given operating point. This concept constitutes the basis of the ”flexibility area” at the TSO-DSO substation.

The activities described in this section cover the tasks in **Step 2** and **Step 3** in Figure 1.

3.1 Background

The methodologies to estimate the aggregated flexibility of the DERs in the distribution grid at the TSO-DSO substation can be classified into two groups: (i) Monte-Carlo-based approaches [35, 36, 37] and (ii) optimization-based approaches [38, 39, 40, 41, 42, 43].

Monte-Carlo-based approaches process a large number of operating points randomly to estimate the feasible flexibility region at the TSO-DSO substation around a given operating point at a given time [35]. Each operating point emulates a combination of the setpoints of all DERs (generation and denamd). The results of an AC power flow for each operating point are used to determine whether the operating point violates any grid constraint or not. The identified feasible operating points are used to approximate the flexibility boundary at the TSO-DSO interface. [36] utilizes a similar approach to estimate the flexibility, considering the time-dependent nature of the flexibility from DERs. [37] emphasizes the need to differentiate the terms feasibility and flexibility, while approximating the flexibility provided by fast and slow responding DERs.

The optimization-based approaches aim to directly identify the boundaries of the flexibility area around an operating point through multiple steps by maximizing the active-reactive power flexibility at the TSO-DSO substation. They require fewer intermediate steps to estimate the feasible flexibility boundaries compared to Monte-Carlo approaches; however, the computational effort in each step is higher, since a non-linear optimal power flow problem is solved at each step. [38] identifies the boundary conditions of the flexibility area by minimizing the reactive power import from the TSO for a selected set of active power setpoints. [39] proposes a non-convex non-linear optimization-based approach accounting for the cost of flexibility. [40] investigates the impacts of the grid components, such as tap changing transformers, active/reactive generation and demand on the estimated flexibility. In both [39] and [40], first, the extreme points of the flexibility area are calculated, minimizing or maximizing the active and reactive power exchange between the TSO and DSO, followed by granulated calculations, based only on the active power exchange, so that the boundaries are refined. [41] proposes to explicitly formulate the time-variant P-Q capabilities of each type of flexibility-providing unit as constraint in the 2-step optimization utilized in [39] and [40]. [42] focuses mainly on the uncertainty of demand and stochastic generation and proposes a scenario-based robust approach to determine the available flexibility.

In this project we focus on determining the aggregated flexibility boundary over a time-horizon (e.g., 1 day in 15-minute resolution) in presence of high shares of DERs, such as solar PVs, EVs, HPs, conventional demand and BESS. We use an optimization-based approach, and expand the methodology introduced in [43] and [44], to obtain the potential contribution of the DERs to the provision of operational flexibility at the TSO-DSO interface. An angular sweeping approach, which will be demonstrated in the following section, is used to determine the boundaries of the flexibility around the operating point at the TSO-DSO substation at each time step. We take into account the PQ capability curves of DERs to account for the active and reactive power flexibility provision of conventional demand, solar PVs, and BESS. It is assumed that HPs and EV charging provide active power flexibility only. The flexibilities that can be provided by on-load tap changing transformers and shunt reactive power devices are ignored in this study.

3.2 Methodology

Figure 13 illustrates the aggregated flexibility of DERs at the TSO-DSO interface substation at a given time. It is noted that at every time instant the available maximum solar PV generation, and the amount of the electric demand changes. Thus, the flexibility area at the TSO-DSO substation is time dependent and the shape will vary at each time instant. Note that the calculation of the flexibility area may be performed by the utility or an aggregator. The presented methodology can be applied either by considering each

DER separately or by aggregating the DERs located in each LV feeder.

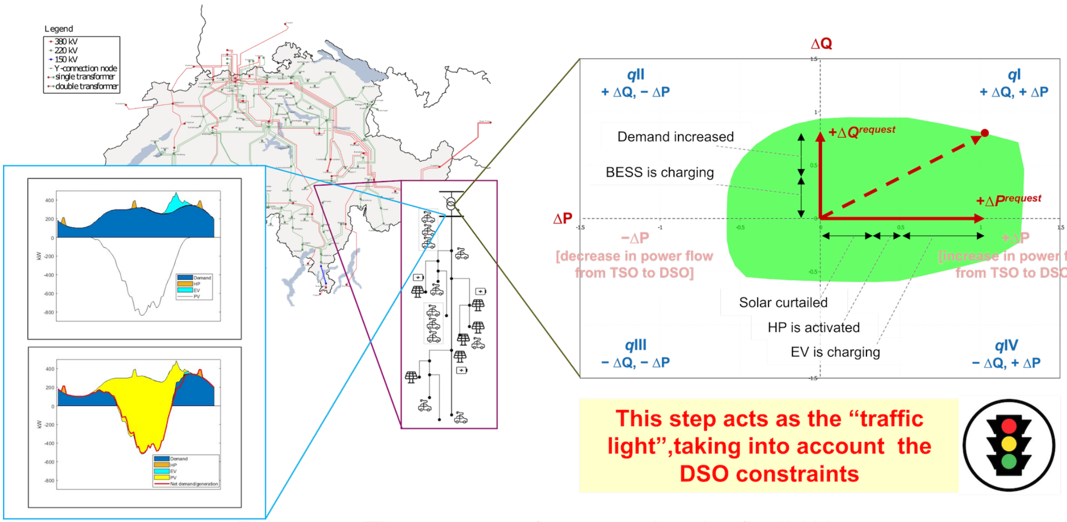


Figure 13: The concept of aggregating the flexibilities

The process to obtain the flexibility region for each time-step is as follows:

Step (1) Solve a power flow for a given time instant to obtain the operating point, with given setpoints of all DERs (i.e., demand, EV charging, HP status, BESS charging and state of charge, solar generation), at TSO-DSO substation (denoted in blue in Figure 14). This step emulates the process where utility calculates the operating point by performing a power flow or state estimation based on the measurements or forecasts of demand and distributed generation.

Step (2) Identify a sweeping angle, $\Delta\theta$, to determine the line (denoted by dotted black line in Figure 14) on which the optimization will be performed to maximize either the active power flexibility (P_{flex}) or the reactive power flexibility (Q_{flex}) or the apparent power ($S_{\text{flex}} = \sqrt{P_{\text{flex}}^2 + Q_{\text{flex}}^2}$).

Step (3) For each $\Delta\theta$ increment, perform an optimization, to maximize the selected quantity (i.e. P_{flex}, Q_{flex} or S_{flex}) depending on the desired use of the flexibility. The process is illustrated in Figure 14. For example, if the DSO will utilize the flexibility area to provide voltage support only (in both directions), then the maximization can be performed on Q_{flex}. If the DSO will utilize the flexibility area to provide balancing service only, then the maximization can be performed on P_{flex}. If the flexibility capability in both directions is desired to be assessed, the maximization is performed on S_{flex}. Note that, essentially, optimization maximizes how much the operating point at the TSO-DSO substation can vary in every direction, thanks to the flexibilities provided by DER, but limited by the grid constraints.

The optimization formulation uses the following list as optimization parameters:

- The P_{flex} and Q_{flex} at the TSO-DSO interface substation
- The P and Q flexibility provided by the conventional demand
- The P and Q flexibility provided by the solar PV
- The P flexibility provided by HPs
- The P flexibility provided by EVs
- The P and Q flexibility provided by BESS
- The bus voltages

The formulation utilizes the following constraints:

- AC power balance equations at each node (*equality constraints*)
- Constraints on bus voltage magnitudes (*inequality constraints*)
- The maximum and minimum P and Q flexibility that can be provided by each DER (*inequality constraints*)

- Line and transformer loading constraints (*inequality constraints*)

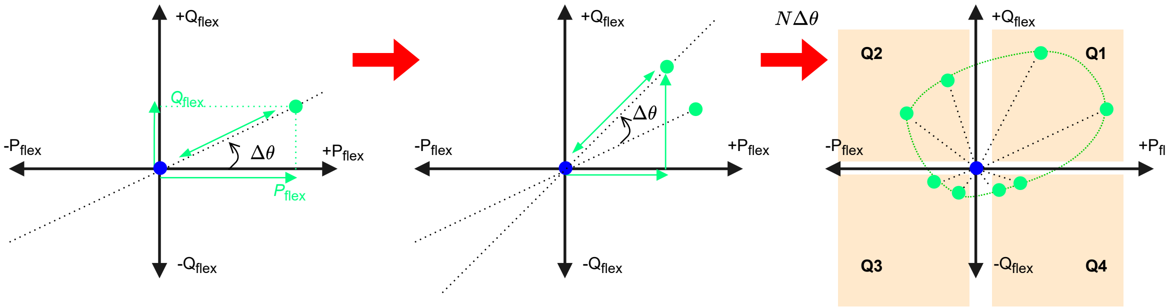


Figure 14: The stepwise process of creating the flexibility boundary at the TSO-DSO substation

Note that, in quadrants 1 & 4 in Figure 14, $P_{flex} > 0$, implying that the TSO is providing more active power to the DSO due to an increase in the consumption (and/or a decrease in the electricity generated by the solar PV, increase in HP consumption, increase in charging BESS or EV), while in quadrants 2 & 3, $P_{flex} < 0$, implying that the TSO is providing less active power to DSO compared to the original operating point (or TSO is receiving active power from DSO) due to a decrease in the consumption (and/or an increase in the electricity generated by the distributed generation, discharging of BESS). The **assumptions** in the analysis are as follows:

- The grid information (i.e. connectivity, line/transformer parameters, ratings) is known. Based on this information, (optimal) power flow analysis can be performed.
- The expected / projected amount of electricity generated by each solar PV as well as the electric demand are known by the utility either week-ahead, day-ahead, or intra-day in high resolution (e.g. every 15 or 60 minutes).
- The utility has the necessary infrastructure to determine the operating point of the system day-ahead as well as intra-day by using (i) the grid information and (ii) the information communicated from the customer-side, i.e., net demand (including excess generation due to not locally consumed electricity generated by the solar PVs).
- The utility has necessary telemetry infrastructure to retrieve voltage and current measurements in high time-resolution from each node in the network including the TSO-DSO interface substation.
- The distributed generation resources (i.e., solar PV) are treated as zero-cost generators for optimal power flow (OPF) analysis.
- The solar PVs can provide reactive power capability (i.e. reactive power flexibility) with respect to a given PQ capability curve. In the illustrative results a V-curve is used, however, any other curve can be adopted, which can be based on future changes in D-A-CH rules.
- The “slack” bus is the node connected to the transmission grid and it is assigned an arbitrarily high cost for OPF analysis.
- Each solar PV owner provides a fixed percentage of flexibility (e.g., curtailment) out of the available PV production (i.e., 10%). This amount can be time-dependent, however, in the illustrative results, it is kept constant at each time instant. For example, 10% of the available solar PV generation at a given time instant can be curtailed. This curtailment can be in the form of storing the energy. How the solar PV owners provides this flexibility (whether via curtailing or storing the energy or converting the energy) is not within the scope of this project.
- Conventional electric demand provides a fixed percentage of flexibility (i.e., 10% of the demand). This amount can be time-dependent, however, in the illustrative results, it is kept constant at each time instant. For example, 10% of the demand at a given time instant can be ramped down or ramped up. This ramping can be realized by changing the setpoints of controllable demand units such as the boiler, the AC unit, etc. How the consumer provides this flexibility (whether curtailing/increasing the consumption of a device, etc.) is not within the scope of this project.
- Conventional electric demand is modelled as constant active and reactive power. Constant-

impedance and constant-current models can also be adopted.

- The network is structurally balanced (i.e. there are no 1-/2-phase feeders connected to a 3-phase feeder).
- The electric demand is balanced at each phase, and, thus, positive-sequence modelling is used.
- The ICT infrastructure is capable of accommodating the data exchange and the reliability requirements.
- The TSO and the DSOs (or the aggregators) have a necessary framework in place, administrating the data exchange as well as the right to utilize flexibility services (e.g., traffic light approach utilized by Swissgrid and ewz in Equigy pilot).

3.3 Illustrative Results

The method is implemented in MATLAB using Yalmip [45] and IPOPT [46], based on the existing in-house tool, FlexOPF. Apparent power is maximized in the AC optimization during the stepwise process in Figure 14. A sweeping angle, $\Delta\theta = 15°$, is adopted to obtain the flexibility boundary at each time step.

Note that the aggregation process can be performed week-ahead, day-ahead or x-hour-ahead depending on the framework, in a sliding-mode manner. As the time-horizon is shorter, the reliability of the solar PV forecasts is higher, which will subsequently impact the charging/discharging behaviour of the BESSs and their available flexibilities. In addition, since the DER owners are assumed to provide an ”availability signal” as described in in Section 2.2, we assume that they will be more conservative in their offering for longer time horizons (such as a week) since they have to provide the signal in e.g. 15-minute resolution for the whole week. Our assessment is that an intraday framework (e.g., x-hour-ahead) and day-ahead frameworks are ideal for utilizing the DER flexibilities in sub-hourly resolutions. Therefore, we selected a day-ahead framework for illustrative purposes. It is assumed that conventional demand, HPs, BESSs and PVs are ”available” on a continuous manner, while the EVs are available at the time of their intended charging and until next morning.

Figure 15 demonstrates a week day in Summer for the ”high” scenario in Table 3, created by using the process described in Section 2.2. The sum of the charging behaviour of all BESSs as well as aggregated PV generation and demand is illustrated in Figure 15. It can be observed that the energy storage systems in the district start charging when there is excess PV generation at $\sim 9:00$, and they start discharging when there is no excess PV at $\sim 17:30$, as explained in Section 2.2. It can be observed that majority of the evening demand is covered by the PV energy stored in BESSs. Note that at times (at night, during early morning hours) when BESSs are fully discharged, they are available to offer ”charging” flexibility, and, similarly, they can offer only ”discharging” flexibility while they are fully charged between $\sim 13:00$ and $\sim 17:30$.

Figure 16 demonstrates the results of the aggregation process at the TSO-DSO substation for selected time instants: 06:00, 11:00, 16:00 and 21:00. Since the operating point at the TSO-DSO substation varies at each time-step, the graphs are shifted to the origin for comparative purposes. Square identifiers are used to denote the maximum active and reactive power flexibilities available at each time step. As an example, the district can provide $\sim 1.7MW$ additional flexibility by increasing the demand at 21:00, $+Pflex$, (curve in magenta), while it can provide$\sim 0.75MW$ flexibility, $-Pflex$, by decreasing the demand and discharging the BESSs.

Similarly, at 06:00 (curve in blue), the district can provide almost only $+Pflex$ by increasing the demand. Note that the main contributors of the flexibility at 06:00 are the BESSs as demonstrated in Figure 17, assuming that the BESSs are ”available” at all times. Overall, BESS contribution to flexibilities at each time instant is significant in the ”high” scenario.

Once the flexibility boundaries are calculated for each time step, in 15-minute resolution for one day,

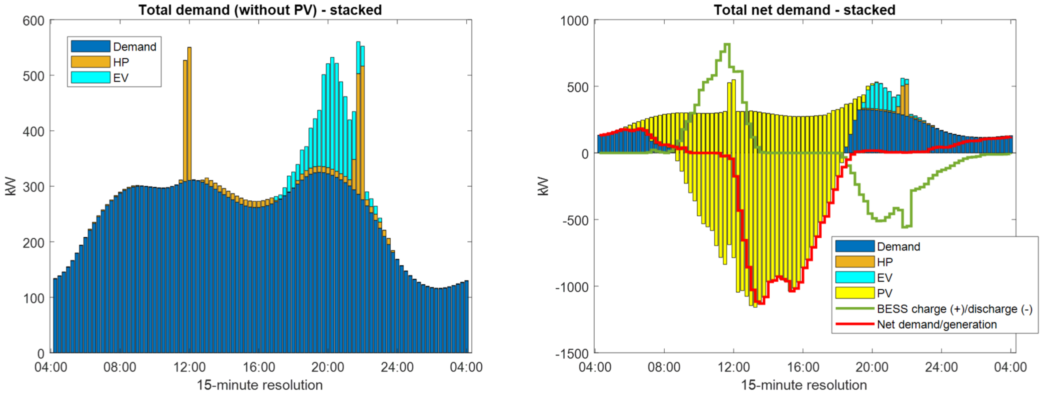


Figure 15: A week day in Summer in high scenario: Total demand, generation and charging/discharging (with and without PV+BESS)

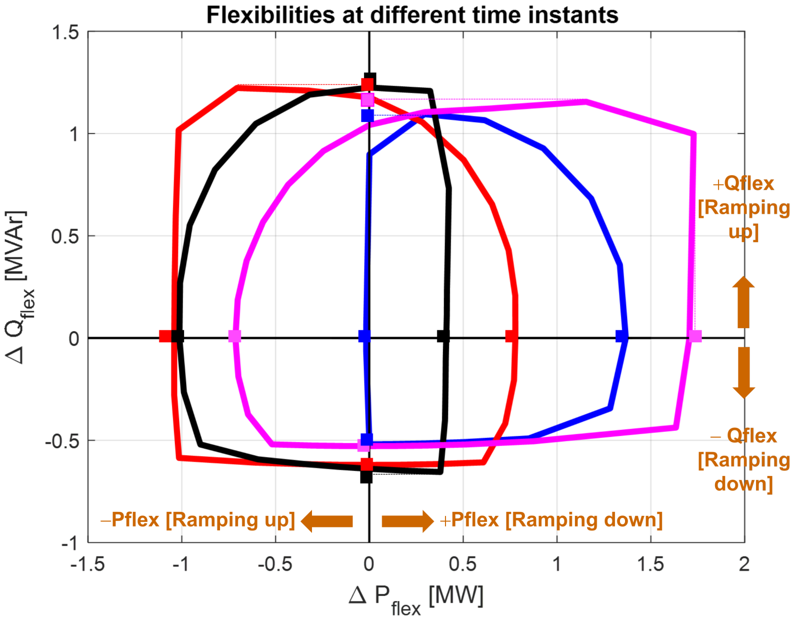


Figure 16: Flexibility area at t=6:00, t=11:00, t=16:00, t=21:00, contributed by all technologies and aggregated at the TS-DSO substation at each time step, for a Summer week day with high solar PV generation

we perform a post processing of the results to identify the maximum and minimum active and reactive flexibilities as well as the contributing DER technology as demonstrated in Figures 18 and 19. We assumed 10% flexibility contribution by the conventional demand, which is on the conservative side. Note that the conventional demand, BESSs, HPs as well as the EV flexibilities can be more reliable than the solar PV flexibilities, which are highly dependent on the PV forecasts as well as the curtailment strategy of the local governments, which might penalize any curtailment. As emphasized in Section 2.2, the ”availability signal” concept allows the DER owners to limit or increase the availability of their assets. Note that we assume that all DERs are continuously availabile, which is very optimistic. Note that, thanks to the converter capability, PV and BESS converters can withdraw/inject reactive power while both charging and discharging.

Finally, Figures 20 and 21 demonstrate the total cost of flexibilities if **maximum** available active

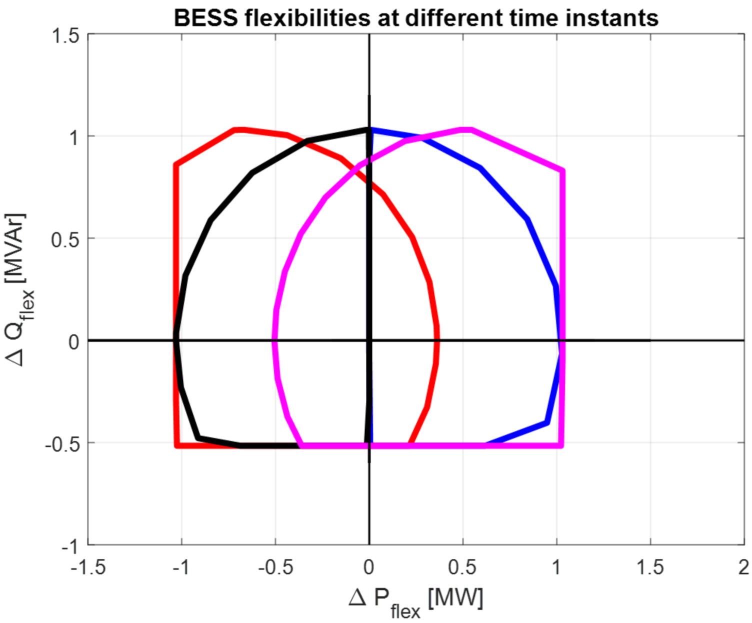


Figure 17: BESS flexibility area at t=6:00, t=11:00, t=16:00, t=21:00, contributed by all BESSs in the district, aggregated at the TSO-DSO substation. Compare with the total flexibility areas

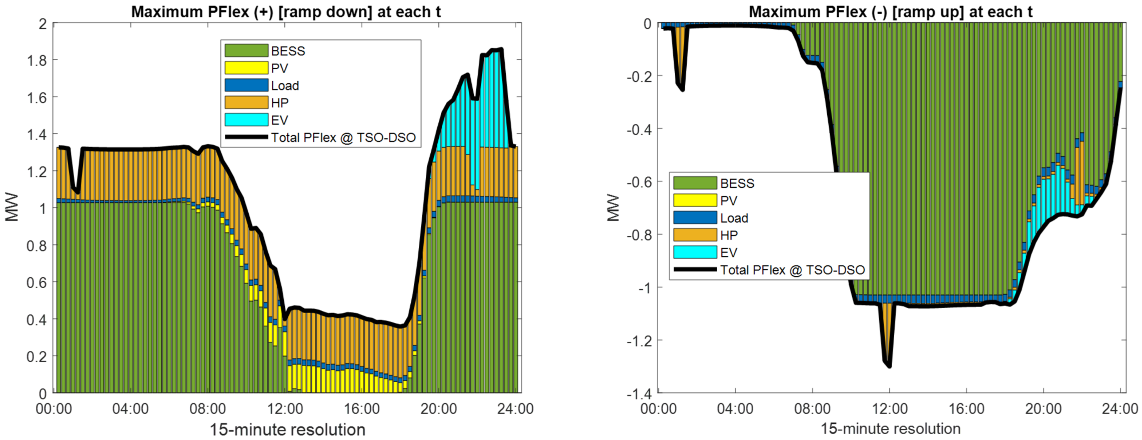


Figure 18: Maximum active power flexibility available at each time instant in both directions. Left: +PFlex [*corresponding to ramping down by increasing demand, curtailing solar PV, charging BESS, acting like a "demand"*], and Right: -PFlex [*corresponding to ramping up by decreasing demand,discharging BESS, acting like a "generator"*]

and reactive flexibilities are utilized. The cost calculation is based on the remuneration assumptions described in Section 2.3 and illustrated in Figure 12. The costs are provided in hourly resolution, for convenience in comparing with the costs of traditional providers of the flexibility as well as the wholesale energy prices. Note that, the flexibility remuneration is driven by different components for different DERs. When providing positive flexibility (+PFlex, + Qflex) corresponding to increasing demand, curtailing PV generation and charging BESSs, the remuneration for any "demand-like" flexibility is driven by the difference between high tariff and low tariff, if there is a 2-tier retail tariff structure, or the difference between the tariff at the time of flexibility and the lower tariff of the day as explained in Section 2.3. However, curtailing solar PV generation is remunerated by using the feed-in tariff as described in Section 2.3. Therefore, since the positive active flexibility that can be offered by BESS by charging is limited between

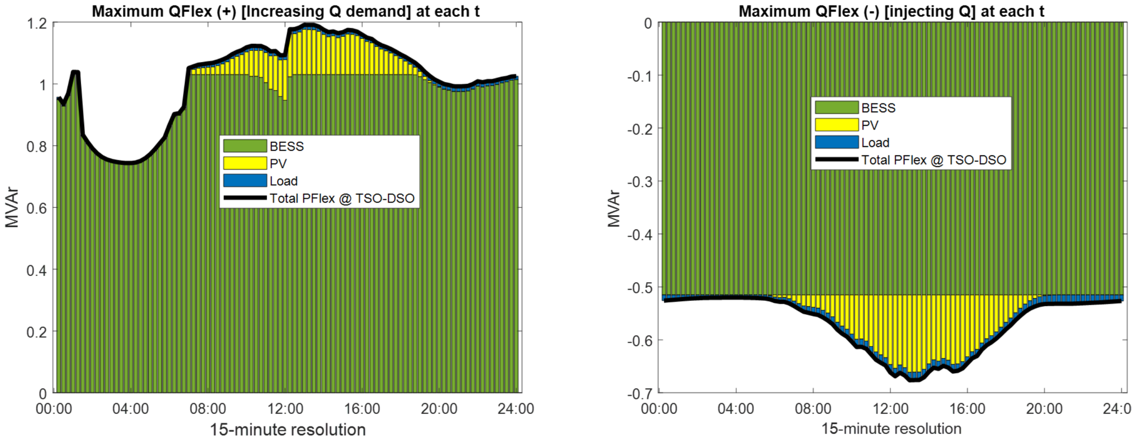


Figure 19: Maximum reactive power flexibility available at each time instant in both directions. Left: +QFlex [*increasing reactive demand*], Right:-QFlex [*decreasing the Q demand or injecting Q*].

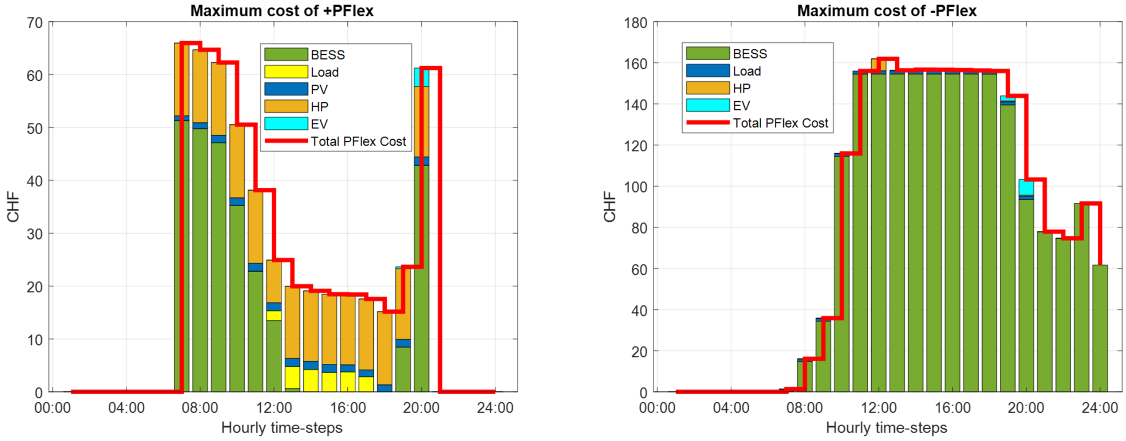


Figure 20: Cost of active power flexibility if maximum available flexibility is used. Left: +Pflex [*ramping down, acting like a demand*], Right: -PFlex [*ramping up, acting like a generator*]

12 : 00 and 18 : 30, the total cost is driven mainly by the amount of the flexibilities offered by other types of demand and the solar PVs.

Note that the cost of providing negative active power flexibility is relatively high, because the amount of the flexibility is mainly driven by the offering of the BESSs (Figure 18), and, as described in Section 2.3, the remuneration is driven by the low tariff so that the DER owners are compensated by the loss of opportunity since they will not be able to discharge the energy in the evening, while the remuneration for other DER types that can provide negative power flexibility is driven by the tariff difference. It is important to reiterate that the reactive power flexibility provision in both directions are contributed significantly by BESSs at the expense of reducing active power-related services or activities and, the reactive power compensation is also driven the same remuneration framework valid for the active power flexibility provision as explained in Section 2.3. Therefore, the reactive power flexibility is considerably higher than those that can be provided by traditional reactive power providers such as conventional generators and shunt devices (reactors, capacitors).

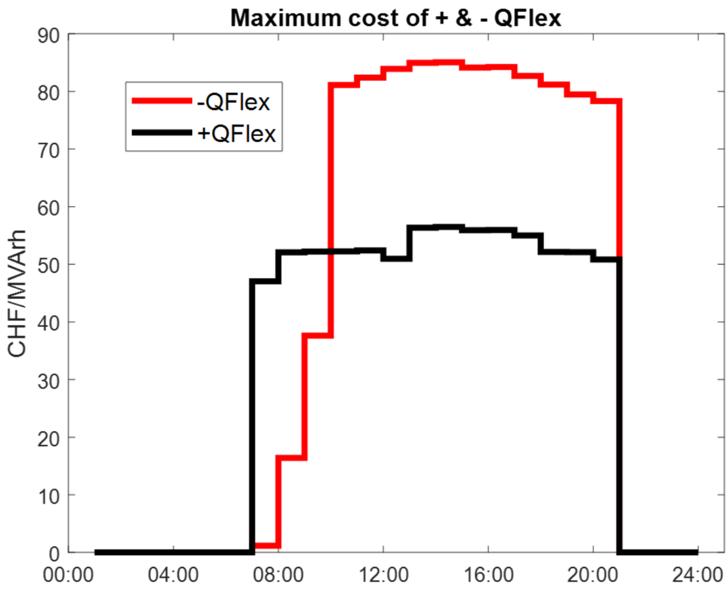


Figure 21: Cost of reactive power flexibility if maximum available flexibility is used: +QFlex [*increasing reactive demand*] and -QFlex [*decreasing reactive demand and/or providing reactive power to the grid*]

3.4 Summary and discussion

It is important to note that aggregated flexibility of one district, shall be further aggregated with the aggregated flexibilities of other districts in LV and/or MV, so that a meaningful amount of total flexibility is achieved for the system benefits. This approach will be employed in the following sections such that the calculated aggregated flexibility is scaled up by a factor, which will produce a reasonable amount (e.g., $\sim\geq 50MW$) for reserves and operation. In order to offer a reliable service to minimize the risk of penalties, it is a crucial task to determine the right amount and type of districts with DERs to be aggregated.

The flexibility aggregation has to be performed at every time instant, depending on the resolution of the services. It is imperative that sub-hourly time resolution (e.g., 5- or 15- minute) is essential to accurately capture the behaviour of the small DERs, and therefore we selected a 15-minute time interval for calculating the flexibility boundaries.

4 Flexibility for transmission reserves

Stable power system operation demands that energy supply and demand be balanced at all times. Balancing the power flow in the electric grid is an ancillary service coordinated by the TSO which has been traditionally provided by the large power generating units. Increased intermittency in energy generation due to renewable sources requires novel solution approaches for reserve energy provision, as on one hand more flexible reserve is required while, on the other hand, large power units are often not dispatched. One such solution could consist in integrating the capabilities of the resources in the distribution system. Local resources however are not large enough to have a direct impact on the transmission system. As a result, smaller storage devices and distributed generators are usually not able to participate individually in reserve provision, which underlines the necessity of aggregating flexible customers on the distribution system side.Typically a market entry threshold is given with a minimum capacity of several Megawatts. It is also important to underscore that those flexibilities might not be available, at least not to their full extent, at all times due to meteorological and user comfort dependencies, further emphasizing the need for an aggregator that can effectively monitor and coordinate the diverse set of resources within a given area. These and other possible situations will be considered for simulation and assessment.

The activities described in this section cover the reserve-related tasks in **Step 4** in Figure 1. The remainder of this reserves assessment section includes: details of the modeling methodology utilized to simulate the dispatch of energy and reserves (Section 4.1), results of the simulations for various scenarios of the configuration of aggregated flexibilities and international system developments (Section 4.2), and a concluding discussion of the key takeaways (Section 4.3).

4.1 Methodology

Modeling the economic dispatch optimization process of modern electricity markets enables a wide range of research including evaluating new technologies, testing new market designs, and analyzing new energy policies. These types of models are indispensable tools for investigating aspects of the electricity system because they can predict market outcomes in a realistic manner, while also being able to spatially track important metrics such as emissions, use of hydro resources, and transmission congestion.

Traditional optimal power flow (OPF) solutions, like those achievable using the MATLAB Power Systems Simulator MATPOWER [47], optimize the output from all generating units to supply the nodal demand while staying within the bounds of the transmission system. Typically such problem formulations refer to one instant in time, ignoring the need to supply reserves, and omitting integer commitment variables. These limitations do not allow typical OPF simulations to represent the ramping limitations of the generation fleet, the cooptimization of electricity and reserves, nor aspects such as outages and scheduling.

The goal of the methodology utilized in this analysis is to implement several of the advanced aspects listed above into available direct current (DC) OPF modeling tools along with available linear solvers to successfully mimic the market-based dispatch of a multi-country region. To properly model the dispatch, the framework described converts the traditional single time step OPF into a multi-time-step problem that includes time-step coupling through generator ramping restrictions. The framework also introduces additional equations and constraints to the OPF that enable simultaneous co-optimization of electricity dispatch and reserve procurement, a process that is essential to any system operator and is key for the evaluation of the competitiveness of the aggregated flexibilities provided by the DERs, hereinafter referred to as **DFlex units** in this section, in the Swiss ancillary service market. Additionally, to represent reasonable market outcomes, the methodology aggregates the internal networks of each market zone and enforces transfer capacity trade limitations between neighboring zones.

While the multi-time-step structure would also enable time-step coupling that accounts for the balance and limits on energy storage volumes for units such as hydro dams, hydro pumps, and BESS, such equations and constraints were not implemented in this work. The extension of this model to include such aspects was beyond the scope of the study.

The other limitation of the utilized model is that it does not include the use of binary variables needed to decide commitment statuses, to implement the corresponding minimum run times, and to allow decommitment of units based on specified minimum sustainable operating levels. While these aspects are important for representing realistic market outcomes, the structure of the region of interest, Switzerland, allows the omission of such variables to be acceptable. Switzerland's electricity generation is supplied by (i) hydroelectric, which essentially have a zero minimum operating level, (ii) nuclear, which are always online and are anyway phased out in the future scenarios, (ii) PV, which are heavily added in the future scenarios and operated as a low-cost curtailable fixed injection, and (iv) imports. For these reasons, there is little benefit to consider commitment variables.

The modeling methodology employed represents the market-based dispatch through solving a DC OPF and by incorporating a multi-time-series structure, cooptimization of electricity and reserves, and ramp rate constraints that impact the temporal electricity and reserves limits of each generator.

4.1.1 Model description

The objective of the DC economic-dispatch model is to co-optimize the operational decisions (i.e., minimize the total system operating costs) of electricity dispatch and reserve procurement to meet the demands across multiple market zones that each possess a mixture of generator types and capacities. This model co-optimizes the dispatch from a central operator perspective with an hourly resolution, taking into account load and generation profiles (i.e., wind, PV, and hydro run of river (RoR)) for a given target week. To this end, the multi-period DC OPF problem is stated as follows:

$$J^* = \min_{u} \sum_{i=1}^{N} l_i(x_i, u_i) \qquad i = 1, ..., N \tag{5}$$

$$\begin{aligned} \text{s.t.} \quad & g(x_i, u_i) = 0 && (6)\\ & h(x_i, u_i) \leq 0 && (7)\\ & x_{min} \leq x_i \leq x_{max} && (8)\\ & u_{min} \leq u_i \leq u_{max} && (9)\\ & Au \leq b\,. && (10) \end{aligned}$$

The problem minimizes the total system operation cost over a scheduling horizon of N discrete time steps with a scalar stage cost function l_i. The linear constraints (6)-(9) represent the standard DC power flow equations [48] at each time step i, including the nodal power balance g, thermal line limits h, and bounds on both the voltage angles x_i and active power injections u_i. The power system state vector x_i is formed of only the voltage angles while the scheduling variable u_i is composed of the n_g generator's active power injection vector $P_i^\mathrm{g} \in \mathbb{R}_{n_\mathrm{g}}$ as well as the procured positive and negative reserve capacities $R_i^\mathrm{up} \in \mathbb{R}_{n_\mathrm{g}}$ and $R_i^\mathrm{down} \in \mathbb{R}_{n_\mathrm{g}}$,

$$u_i = [{P_i^\mathrm{g}}^T, {R_i^\mathrm{up}}^T, {R_i^\mathrm{down}}^T]^T \tag{11}$$

forming the decision vector

$$u = [u_1^T, u_2^T, ..., u_N^T]^T \tag{12}$$

that is selected during the optimization for a cost effective solution.

In addition to these linear power flow constraints, that are decoupled in time, the affine constraints (10) of the decision vector are potentially coupled in time. Such a constraint is typically used for a multi-period formulation including storage devices [49] but can also be used to model reserve procurement and rate constraints as follows. First, the reserve quantities are either positive or negative

$$R_i^{\mathrm{up}} \geq 0 \qquad R_i^{\mathrm{down}} \leq 0 \tag{13}$$

and have to meet the total reserve requirements $R_{\mathrm{total}}^{\mathrm{up}} \in \mathbb{R}$ and $R_{\mathrm{total}}^{\mathrm{down}} \in \mathbb{R}$,

$$\sum_{j=1}^{n_{\mathrm{g}}} R_{i,j}^{\mathrm{up}} = R_{\mathrm{total}}^{\mathrm{up}} \qquad \sum_{j=1}^{n_{\mathrm{g}}} R_{i,j}^{\mathrm{down}} = R_{\mathrm{total}}^{\mathrm{down}} \tag{14}$$

In the case of deployment, the procured reserve capacities have to respect the generator's minimum power $P_{\mathrm{min}} \in \mathbb{R}_{n_{\mathrm{g}}}$ and maximum power $P_{\mathrm{max}} \in \mathbb{R}_{n_{\mathrm{g}}}$,

$$P_i^{\mathrm{g}} + R_i^{\mathrm{up}} \leq P_{\mathrm{max}} \qquad P_i^{\mathrm{g}} + R_i^{\mathrm{down}} \geq P_{\mathrm{min}} \quad . \tag{15}$$

Finally, the rate limitations of the generators $r^{\mathrm{up}} \in \mathbb{R}_{n_{\mathrm{g}}}$ and $r^{\mathrm{down}} \in \mathbb{R}_{n_{\mathrm{g}}}$ have to be respected in normal conditions and during deployment of the reserves,

$$\frac{P_{i+1}^{\mathrm{g}} - P_i^{\mathrm{g}}}{T_{\mathrm{P}}} + \frac{R_i^{\mathrm{up}}}{T_{\mathrm{R}}} \leq r^{\mathrm{up}} \quad , \tag{16}$$

$$\frac{P_{i+1}^{\mathrm{g}} - P_i^{\mathrm{g}}}{T_{\mathrm{P}}} + \frac{R_i^{\mathrm{down}}}{T_{\mathrm{R}}} \geq r^{\mathrm{down}} \quad , \tag{17}$$

where T_{P} denotes the length of time between consecutive energy market clearing intervals and T_{R} the minimum length of time which a generators procured reserve has to guarantee to be able to fully deploy. The given formulation implicitly assumes $T_{\mathrm{R}} \leq T_{\mathrm{P}}$. The constraints (13)-(17) are defined for all time steps $i = 1, 2, ..., N$ to form the affine constraints (10).

This optimization problem is a general case of the standard linear DC OPF problem. The problem is implemented using the interfaces of the MATLAB Toolbox MATPOWER [47] and solved using the linear optimization package GUROBI [50]. For the implementation, the initial single time step problem is copied N times and augmented with the appropriate renumbering and linear constraints (10) on the decision variables.

For the simulation a time horizon of 1 week is chosen with 1 hour time intervals (i.e., T_{P} = 60min). Zonal electricity load profiles are defined as described in Section 2.1.3. In addition to meeting the electricity demand at each time step, the co-optimization has to procure a certain amount of 10-minute reserves (i.e., T_{R} = 10min) for the Swiss zone only. The Swiss reserve requirements are defined as a constant 400 MW of positive capacity and 400 MW of negative capacity. These values represent an average requirement for the Swissgrid secondary control reserves. The uncertainties of how reserve requirements might change in the future were not factored into this investigation. The reserves are procured from all qualified Swiss generators, which for this assessment were specified as only the hydro dam, hydro pump, and DFlex units. Since the balance and constraints on energy storages are not accounted for, all hydro pump capacities are reduced by 50% to reduce the impact their constant utilization could have on the results. Similarly, utility-scale BESS capacities are omitted from the model.

The overall objective of the co-optimization, specified through the functions l_i, is the minimization of the total energy production and reserve procurement cost of the system according to the marginal energy and reserve procurement prices defined for each generator. Energy offer prices reflect the projection of VOM costs, fuel prices, and $\mathrm{CO_2}$ prices as discussed in Section 2.1.2. In addition, reserve offer prices are defined for the DFlex unit as described in Section 2.3 and for all other units as detailed in the following section. While the deployments of reserves are not simulated, the reserves can entail direct costs for their procurement and they also cause opportunity costs if power production from a cheap unit has to be shifted to more expensive units to meet the reserve requirements. This concept of lost opportunity cost in relation to the reserve pricing is discussed more in the next section.

4.1.2 Reserve bids and costs

In a typical market setting today, the reserve prices are set based on the offer prices of the cleared positive and negative capacity offers. Generating asset owners set their own offer prices representing the minimum amount they must be paid to provide their generating capacity as a reserve and they use a range of different logic and forecasts to quantify their offer prices. One key influencing factor for reserve offer prices is the amount of profit that will be foregone (i.e., not earned) because this reserve power capacity is being held on standby and not providing electricity and therefore receiving the wholesale electricity price. This is a concept known as lost opportunity cost. From the perspective of the asset owner, the profit foregone (or lost opportunity) for any amount of capacity offered as a reserve should at least be compensated with equal profit by the reserve clearing price. So, an asset owner would be wise to set an offer price for reserve capacity such that if this price ends up being the clearing price (which would mean their offer is cleared) then they would earn an identical amount of profit as if they were instead paid the wholesale electricity price. In fact, the asset owner in this case would hope that their offer was not the last offer cleared and the resulting reserve clearing price would actually be higher than their reserve offer price and hence earn additional rents.

Since the variable operating costs of reserving power capacity is generally much lower than actually generating with the same capacity, the reserve offer price required to earn the same profit (i.e., revenue - cost), tends to be lower than the wholesale electricity price. However, this equal profit calculation is of course much more complicated because of other factors, such as: the likelihood of being called up (also known as deployed) to provide some of the reserve power and uncertainty associated with forecasting the wholesale electricity price since it is not known prior to making reserve capacity offers. In the end, asset owners must rely on a host of factors, like forecasts for electricity prices, recent trends of the reserve clearing prices, and past experience to determine their offer prices for reserve capacity offers. After all reserve power and price offers are provided to the market, the clearing selects the lowest cost offers until the total reserve requirement is supplied and generally the most expensive cleared offer sets the clearing price that all cleared offers are paid (this process is known as pay-as-cleared).

In the model utilized for this reserve assessment, the influence of lost opportunity is inherently captured for upward reserves based on the co-optimization of both energy and reserves demands. Since being procured for upward reserves results in a direct profit loss since the wholesale electricity price is not earned, the reserve up prices will tend to follow the wholesale electricity prices (see Fig 23d). No additional direct costs are therefore included for non-DFlex generators that offer capacity as upward reserves. Since DFlex itself does not offer power in the energy market, it has no lost opportunity and instead uses a direct reserve procurement cost based on the hourly price profile created from the remuneration scheme in Section 2.3.

However, since being procured for downward reserves does not entail a direct loss of profit (i.e., the generator is still producing and selling electricity), no inherent accounting of lost opportunity is reflected in the modeled downward reserve prices. In fact, unless some other direct costs for generators that provide downward reserves are included, the modeled clearing prices for downward reserves will tend to be zero. This model result is also influenced by the lack of modeling reserve deployments since the deployment of a downward reserve would result in a direct loss of profit. Hence, to provide more realistic representation of the downward reserve prices, the DFlex and all other generators offering downward reserves will be modeled with a direct reserve procurement cost.

While the downward reserve procurement cost of DFlex is based on the hourly price created from the remuneration scheme, the cost for all other generators are not known. To set a reasonable procurement cost for all conventional generators, price data were gathered from Swissgrid for the 2020 tenders (paid for procurement) and for the 2020 deployments of downward secondary control reserves. Using the average tender price and the average deployment price along with a probability of deployment of 90%, an average payment is estimated for downward secondary reserves of around 29 EUR/MWh. Before applying this cost to the non-DFlex generators, we also take into account that the deployment portion of this cost is directly dependent on the wholesale electricity price. Since we simulate one summer and one winter week in a future year, the wholesale prices are not expected to remain the same. By comparing the wholesale price results from the simulated 2020 and 2050 winter and summer weeks, we determine a final reserve downward cost for all conventional generators of 24 EUR/MWh in winter and 44 EUR/MWh in summer. These prices are applied to the conventional units and will influence the competitiveness of DFlex. And while many assumptions are used to set these prices, the costs of DFlex also have vast uncertainties and this assessment is not intended to specify if DFlex is cost competitive but instead to investigate the possible system benefits and key factors of sensitivity for offering DFlex capacity as a reserve.

4.1.3 Simulated scenarios and DFlex representation

As detailed in Section 2.1, these simulations are for a future 2050 year based primarily on the projections of the ENTSO-E TYNDP 2020 [12] and the SFOE Energieperspektiven 2050+ [18] with a reduced representation of the transmission network into the five modeled market zones (CH, DE, FR, IT, and AT). For all modeled scenarios, one winter and one summer week are selected for simulation based on the pattern of their demand and RES generation to well represent the overall behavior and impact of DFlex when available for reserve procurement.

To assess the impact of the utilization of DFlex for providing capacity reserves (i.e., ancillary services), first, the time-series and the aggregated flexibilities calculated in Section 3 for a selected grid and a district are scaled up to emulate that an aggregator assembled flexibilities offered by $\sim$ 50 communities throughout the country, and, following, a number of scenarios are simulated to cover a broad range of possible local trends involving the DFlex units (Section 4.2.3) and possible international trends involving the system conditions (Section 4.2.4). Additionally, the last scenarios illustrate the impact as the number of participating DFlex communities is scaled up (Section 4.2.5). Table 5 outlines the criteria that define each of the thirteen scenarios.

Related to the local trends in the communities that make up a DFlex unit, sensitivities are performed related to the amount of BESS available (BESS Level), the difference between the consumer's high and low electricity tariffs (Δ Tariff Level), and the price paid for any electricity consumers feed back into their local grid (Feed-In Price Level). Other scenarios instead compare the impact of DFlex when the system conditions among the five countries simulated change, including both reduced and expanded transfer capacities for Switzerland (CH Grid Transfer Capacity), a much higher price for natural gas (Gas Price), and a lower RES penetration (RES level). Finally, the last two scenarios demonstrate the impact of DFlex as the number of participating communities is scaled up from 50 communities to 100 and 400 communities (Number Participating Communities). The Base scenario, which serves as the comparison for all other scenarios, represents the 50 participating communities as one DFlex unit including a high penetration of BESS, a medium difference between high and low consumer tariffs, and a medium feed-in price. For this base case, the grid transfer capacity, gas price, and RES level are all set based on current expectations (i.e., using the current projections for the Swiss NTC limits, gas prices, and RES levels).

In this reserve assessment, both the upward and downward active power capabilities of DFlex are separated into two components since the costs of some contributors are different than others. For upward active power (DFlexUp), the contributions from conventional demand, HPs and EVs, which

Table 5: Simulated scenarios for the assessment of the utilization of DFlex for reserves.

Scenario	ScenID	BESS Level	Δ Tariff Level	Feed-In Price Level	Number Participating Communities	CH Net Transfer Capacity	Gas Price	RES Level
NoDFlex	s0	–	–	–	0	NTC	As Proj	As Proj
High BESS (Base)	s1	High	Med	Med	50	NTC	As Proj	As Proj
Med BESS	s2	Med	Med	Med	50	NTC	As Proj	As Proj
Low BESS	s3	Low	Med	Med	50	NTC	As Proj	As Proj
Low Δ Tariff	s4	High	Low	Med	50	NTC	As Proj	As Proj
High Δ Tariff	s5	High	High	Med	50	NTC	As Proj	As Proj
Low FeedIn	s6	High	Med	Low	50	NTC	As Proj	As Proj
High FeedIn	s7	High	Med	High	50	NTC	As Proj	As Proj
Reduced CH NTC	s8	High	Med	Med	50	$^1/_3$*NTC	As Proj	As Proj
Expanded CH NTC	s9	High	Med	Med	50	GTC	As Proj	As Proj
High Gas Price	s10	High	Med	Med	50	NTC	High	As Proj
Low RES	s11	High	Med	Med	50	NTC	As Proj	Low
High Participants	s12	High	Med	Med	100	NTC	As Proj	As Proj
Very High Participants	s13	High	Med	Med	400	NTC	As Proj	As Proj

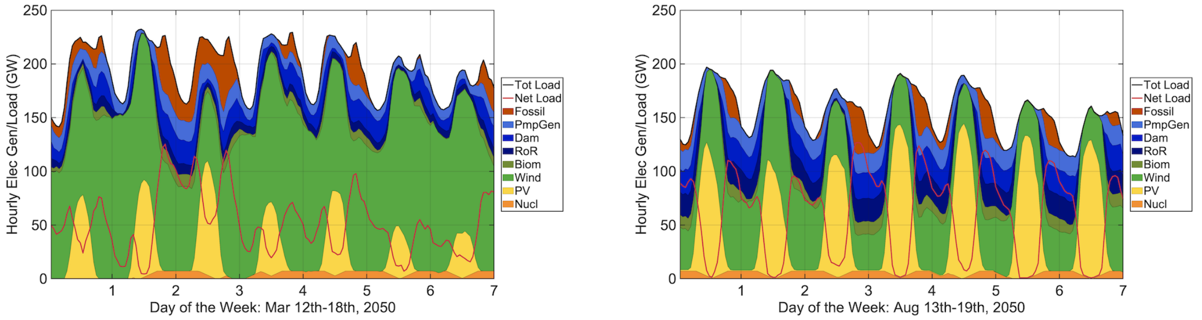
have identical cost remuneration values, are grouped into one category (DFlexUp1) while the contributions from BESS, that have noticeably different remuneration values are put into the other category (DFlexUp2). The upward power flexibility of DFlexUp1 represents the ability for a decrease in the consumption from conventional demand, HPs, and EVs; while the upward power flexibility of DFlexUp2 represents the ability of the BESS to discharge more power. Similarly, for the downward active power (DFlexDn), contributions from conventional demand, HPs, EVs, and BESS are combined (DFlexDn1) while the contributions from PV are kept in a separate category (DFlexDn2). The downward flexibility of DFlexDn1 represents a possible increase in the consumption from conventional demand, HPs, and EVs along with the ability of the BESS to charge more; while the downward flexibility of DFlexDn2 represents the possibility to curtail excess PV injections. Each of these four groups of components in the participating DFlex community is modeled as a separate generating unit, with unique power and cost parameters, offering to sell capacity into the reserve up or reserve down market. These DFlex units are modeled with hourly profiles for their available real power and their required offer prices for this power. The hourly DFlex profiles are derived using the methodology detailed in Section 2.2 (available real power) and Section 2.3 (offer prices).

4.2 Quantitative results

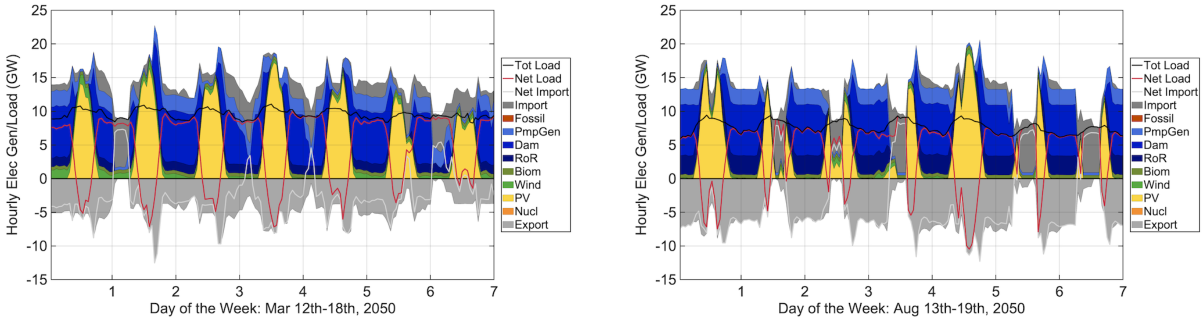
In the sections that follow, the impacts of DFlex being available for providing system capacity reserves are assessed and compared among the scenarios. First, the conditions of the energy and reserve dispatch are introduced for the case without any DFlex in Switzerland (Section 4.2.1). Next, details of the base-case scenario are provided (Section 4.2.2) that serve as a comparison for the sensitivities related to local trends involving the DFlex unit (Section 4.2.3) and international trends involving the system conditions (Section 4.2.4). Lastly, a sense of how the impacts scale is provided by progressively increasing the number of DFlex participating communities in Switzerland(Section 4.2.5).

4.2.1 System conditions without DFlex

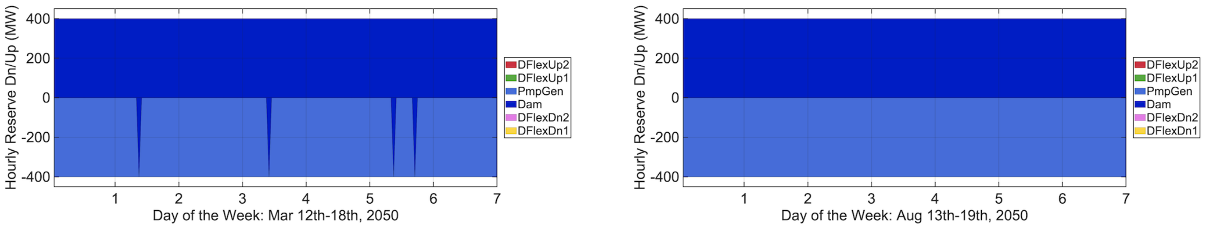
As a reference, before results involving the DFlex units are discussed, results of the scenario s0 ('NoDFlex') are shown to provide context for the electricity and reserve dispatch for the system prior to the availability of any DFlex units for reserve procurement. Figure 22 illustrates the electricity dispatch by generator type for the central EU region (top row) and for Switzerland (second row) as well as the reserve procurement by generator type for Switzerland (bottom row). Figure 23 illustrates the resulting hourly wholesale electricity prices for each country (top row) and the electricity and reserve prices for Switzerland (bottom row). The left column shows the results of the winter week while the right column shows the summer week.



(a) EU Generation - Winter (b) EU Generation - Summer



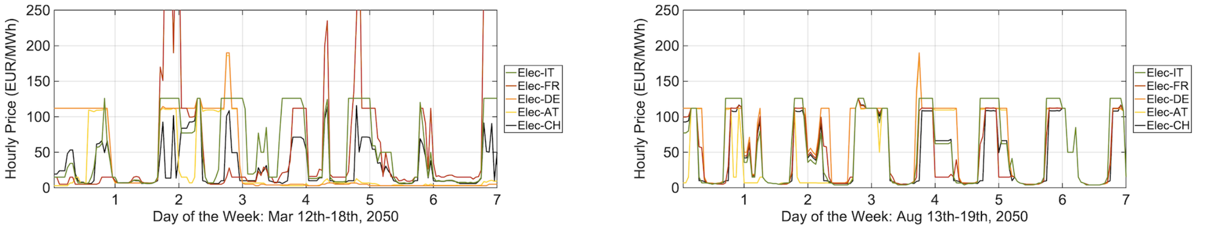
(c) CH Generation - Winter (d) CH Generation - Summer



(e) CH Reserve Procurement - Winter (f) CH Reserve Procurement - Summer

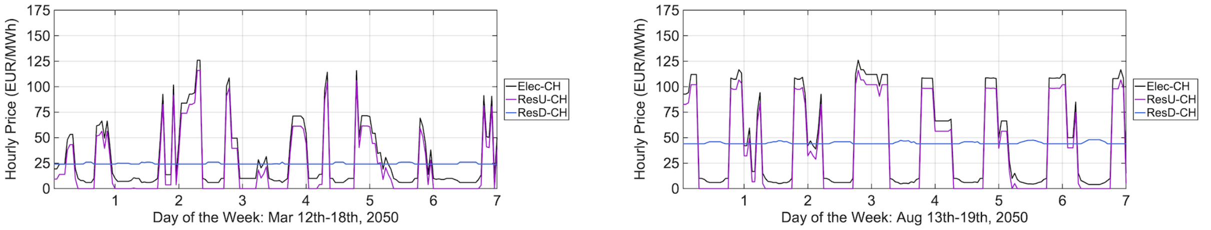
Figure 22: No DFlex: electricity production by generator type for central EU region (top row) and Switzerland (second row) and reserve procurement for Switzerland (bottom row). Winter week on left side and summer week on right side.

The electricity production in the five EU countries is dominated by wind and PV with contributions also from hydro, nuclear, fossil generator types. In winter (22a), wind makes a up a majority with fossil units supplying during the evening peaks. While in summer (22b) PV becomes more significant. During many of the sunny afternoon hours, the combination of wind and PV is able to supply nearly all the energy demands of the five countries, resulting in a almost zero net load. For Switzerland, (22c) and (22d), the production is almost entirely coming from PV and hydro generators with a clear pattern of exporting power except during non-sunny hours when no fossil generators are used in other countries. The amount of PV production causes the Swiss net load to be negative each day (i.e., PV supplies more than the entire Swiss energy demand). On several days the abundance of lower cost non-Swiss RES causes curtailment of the Swiss PV in favor of importing. The Hydro dam and pump units supply the upward and downward reserves, (22e) and (22f), with a preference for hydro dams to supply the upward and hydro pumps to supply the downward. This trend is a result of the lower total variable costs of hydro pumps and the lack of modeling charging behavior. In the results sections that follow, the EU and CH dispatch plots will not be shown because for almost all cases the use of DFlex for reserves has only a small impact on the overall dispatch.



(a) EU Electricity prices - Winter

(b) EU Electricity prices - Summer



(c) CH prices - Winter

(d) CH prices - Summer

Figure 23: No DFlex: wholesale electricity prices for each country (top row) and the electricity and reserve prices for Switzerland (bottom row). Winter week on left side and summer week on right side.

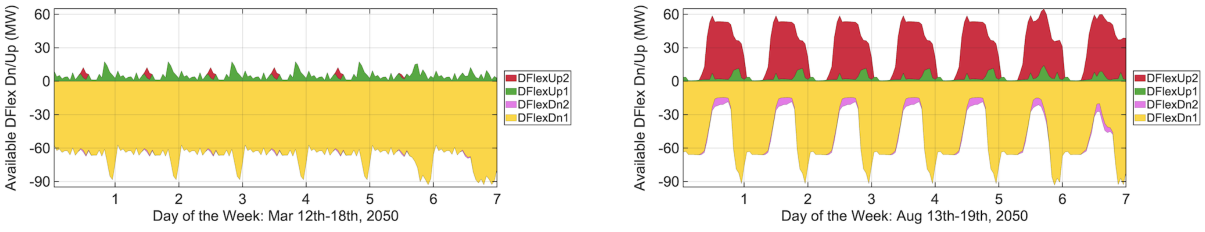
The electricity prices for each country, (23a) and (23b), tend to fluctuate daily to above 100 EUR/MWh during hours where natural gas generators are used with France having the largest spikes in winter to over 250 EUR/MWh. Switzerland appears to have some of the most moderate high electricity prices. The relationship between the electricity and reserve prices in Switzerland, (23c) and (23d), indicates the connection between the upward reserve price and the electricity price. This relationship is a results of the inherent modeling of lost opportunity cost for upward reserves, as discussed in Section 4.1.2. While the upward reserve tracks the dynamic of the electricity price, the downward reserve remains moderate and steady only minor upward bumps during the hours with very low net load. During these hours the price increases because the hydro pump must remain online producing energy so it has available downward capacity to supply the reserve even though this pump unit is more expensive than the available wind and PV. Overall, while the many assumptions utilized in these simulations detract from confidence in the resulting market prices, the prices do fit within the expected range and will provide a reasonable reference to understand if the remuneration requirements of DFlex enable it to fall within the same range. In the results sections that follow, the energy price plots will not be shown because for almost all cases these prices maintain their behavior. Instead the focus will shift to the DFlex power and prices along with the reserve procurements.

4.2.2 Base case: basics of use and impact

To serve as the basis for all other scenario comparisons, the base case scenario s1 ('High BESS') represents a single DFlex unit as an aggregation of 50 participating communities, with a high level of BESS penetration, a medium tariff delta, and a medium feed-in price. This scenario also reflects the expected development of the system conditions, including the projections for the Swiss NTC limits, gas prices, and RES levels.

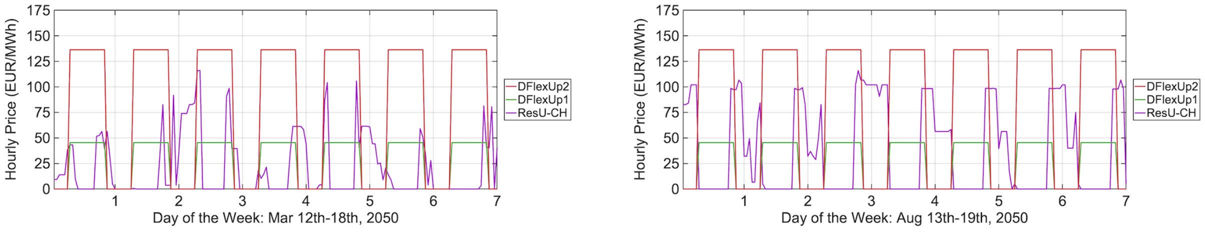
The results will show how BESS dominates the available flexible power capabilities of DFlex; the DFlex prices are low enough in some hours each day to be procured, especially from DFlexDn1; and the procurement of reserves from DFlex replaces hydro capacities allowing them to be utilized more effectively for the energy market, reducing the total system dispatch costs.

Figure 24 illustrates the positive and negative power available from DFlex, Figure 25 compares the reserve prices with those of DFlex and Figure 26 shows the resulting Swiss reserve procurements including from DFlex.

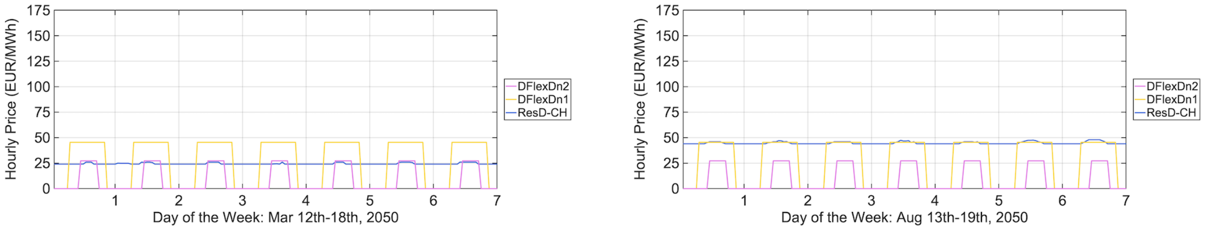


(a) DFlex power available - Winter (b) DFlex power available - Summer

Figure 24: High BESS: positive and negative active power available from DFlex.



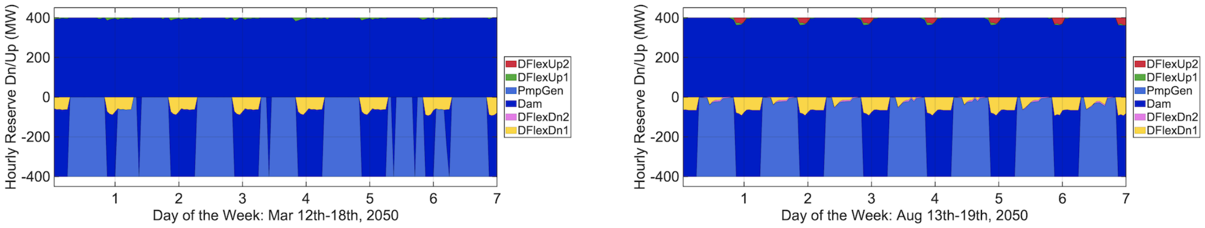
(a) Upward reserve and DFlex prices - Winter (b) Upward reserve and DFlex prices - Summer



(c) Downward reserve and DFlex prices - Winter (d) Downward reserve and DFlex prices - Summer

Figure 25: High BESS: upward reserve and DFlex prices (top row) and downward reserve and DFlex prices (bottom row).

The contributions of DFlexUp2 and DFlexDn1 dominate the power availability of the DFlex unit. Both



(a) CH Reserve Procurement - Winter

(b) CH Reserve Procurement - Summer

Figure 26: High BESS: reserve procurement for Switzerland.

of these are composed primarily (DFlexDn1) or entirely (DFlexUp2) of contributions from the BESS. The pattern of availability in the summer week is influenced much more by the pattern of the PV generation than in the winter week. The prices of both DFlexUp components tend to have an inverse relationship with the reserve up price (i.e., when DFlexUp prices are high the reserve prices are low and vice versa). Only during the evening and morning hours are the prices for DFlexUp below that of the upward reserve, during which the DFlexUp prices are zero. However, it is also during these times when there is little or no available upward power flexibility from either DFlexUp components. In contrast, the DFlexDn prices have a significant number of hours when their prices are below the downward reserve price and they have noticeable amounts of power available. These relationships between the DFlex prices and reserve prices directly influence the hours when DFlex capacity is procured for reserves. In any hour when the DFlexUp or DFlexDn prices are below the associated reserve price, all of the available DFlex power is procured for reserves (i.e., the result is all or nothing). It is clear that the DFlexDn1 has the greatest potential for reserve procurements in this base case because it is the only component that has significant available power during hours when it price is below the reserve price.

Now that the availability, prices, and procurements of the DFlex components are established, the question becomes, what are the impacts of its use for capacity reserves? In this base case, and in all scenarios that follow, the impact of procuring DFlex for reserves is consistent. First, the procured DFlex reserve replaces and relieves capacity from the hydro dam and hydro pump, making these capacities available to produce more (or less) energy. In the case of the upward reserves, the relieved hydro capacities low costs does incentivize them to produce more energy, in turn replacing energy that was otherwise produced from more expensive generators (i.e., like gas units). This change yields a savings in the total costs of energy dispatch over each week simulated. Alternatively, in the case of the downward reserves, the relieved hydro capacities do not generally make a similar impact since the hydro generators are already producing energy to be able to offer the downward reserves and would not be able to produce more. However, in several of the summer days during the mid-afternoon, Switzerland curtails all possible generation and instead imports cheap power from its neighbors. During these hours, prior to the use of DFlex some hydro capacities were required to still produce energy solely so they could also supply downward reserves (these hours resulted in a small increase in the downward reserve prices in Figures 23c and 23d). After the procurement of DFlex for downward reserves during these same hours, the requirement for these hydro units to produce energy is reduced allowing more lower cost imports to instead be used. This result, while only occurring in some hours, also yields lower total dispatch costs for the 5 country system in each week simulated. Overall, the availability and utilization of DFlex for capacity reserves in the two simulated weeks (winter/summer) reduces the total dispatch costs for the energy and reserve markets by around 130’000 EUR (winter) and 325’000 EUR (summer).

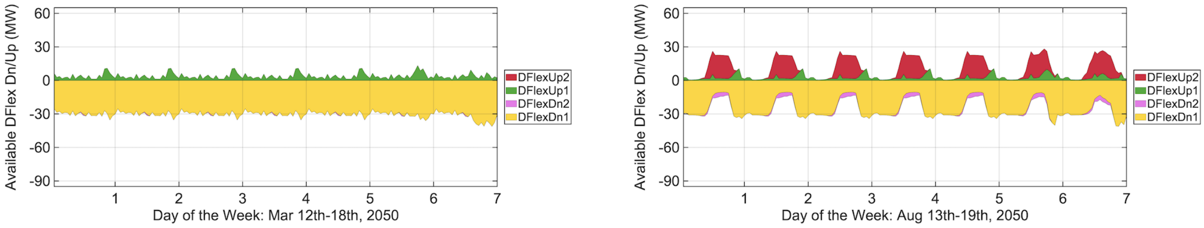
4.2.3 Sensitivities: local trends

The sensitivities in this section are aimed at the relevant local conditions that have a strong influence on either the available DFlex power or the price for the DFlex power. Both aspects could lead to a different scale of benefits from use of DFlex for capacity reserves. First, the importance of BESS towards the amount of positive and negative power DFlex can offer is highlighted, followed by the influence on the DFlex offer price of the consumer's ∆ tariff and feed-in price.

The results will show that a reduction in the amount of BESS directly reduces the amount of available and procured power from DFlex as well as the savings achieved compared with the 'High BESS' scenario; changing the consumer's ∆ tariff can lead to improvements in the utilization of DFlexDn1 (lower ∆ tariff) and an increased use of the flexibilities of BESS; changing the consumer's feed-in price can lead to a more cost competitive use of PV flexibilities (lower feed-in) albeit with small overall impacts.

Reducing the penetration of BESS As discussed in Section 2.2, the available DFlex active power is a combination of contributions from BESS, PV, HPs, EVs, and conventional loads. Out of these sources of flexibility, BESS contributes the largest portion of the positive and negative active power capability, as shown is Section 3. To demonstrate how important BESS is to the impact of using DFlex for reserves, two scenarios s2 ('Med BESS') and s3 ('Low BESS') are created that represent progressively lower levels of BESS penetration in the DFlex communities. The total capacity of BESS in the 'High BESS' case is 51.5 MW, which reduced to 21 MW and 4.5 MW in the 'Med BESS' and 'Low BESS' scenarios, respectively. Since the level of BESS does not impact the remuneration of DFlex, the upward and downward price plots will be the same as in the 'High BESS' scenario and are not shown here.

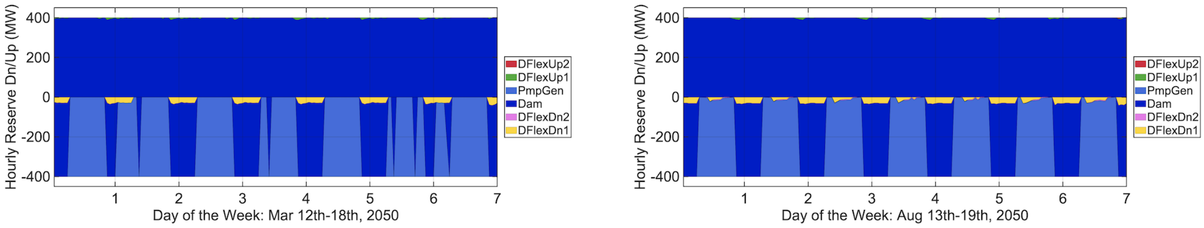
Figure 27 illustrates the positive and negative power available from DFlex and Figure 28 shows the resulting Swiss reserve procurements including from DFlex for the scenario with a medium penetration level of BESS. Similarly, Figure 29 illustrates the positive and negative power available from DFlex and Figure 30 shows the resulting Swiss reserve procurements including from DFlex for the scenario with only a low penetration level of BESS.



(a) DFlex power available - Winter (b) DFlex power available - Summer

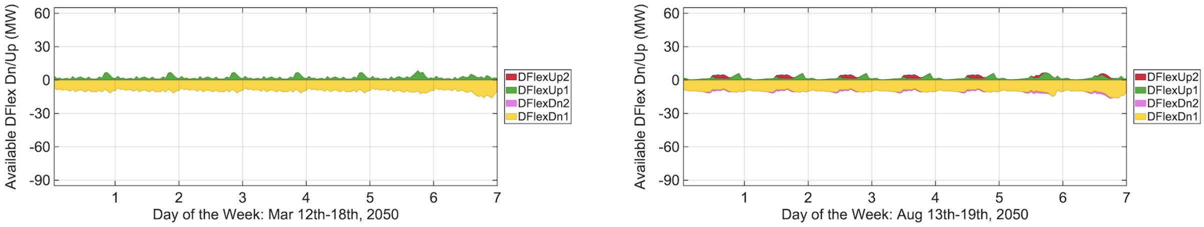
Figure 27: Med BESS: positive and negative active power available from DFlex.

Since BESS makes up a majority of the DFlexDn1 and all the DFlexUp2, which together account for the bulk of the available DFlex power, the reduction in size of BESS directly reduces the amount of available power as well as resulting procured power from DFlex. While the impacts on cost follow the same logic as the 'High BESS' scenario, the magnitude of the savings is reduced with each step down in available BESS penetration, yielding saving of around 45% (Med BESS) and 15% (Low BESS) of those achieved in the 'High BESS' scenario. Figure 31 illustrates how the savings develop as the capacity of BESS in DFlex scales up from 4.5 MW to over 50 MW. The savings scale up smoothly as the BESS level increases. Over the two weeks of the 'High BESS' scenario, the use of DFlex for reserves achieves a savings of over 450'000 Euro.



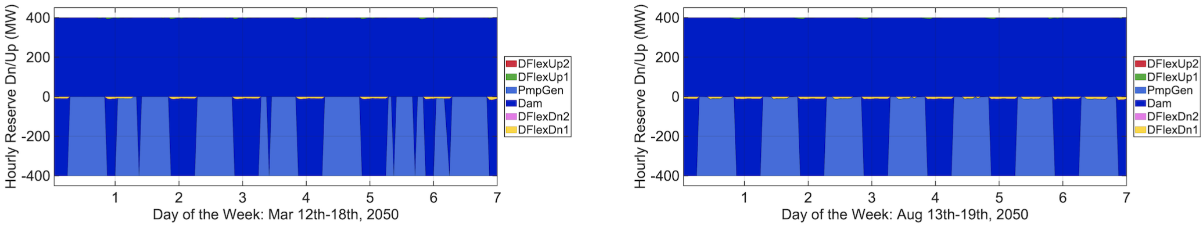
(a) CH Reserve Procurement - Winter (b) CH Reserve Procurement - Summer

Figure 28: Med BESS: reserve procurement for Switzerland.



(a) DFlex power available - Winter (b) DFlex power available - Summer

Figure 29: Low BESS: positive and negative active power available from DFlex.



(a) CH Reserve Procurement - Winter (b) CH Reserve Procurement - Summer

Figure 30: Low BESS: reserve procurement for Switzerland.

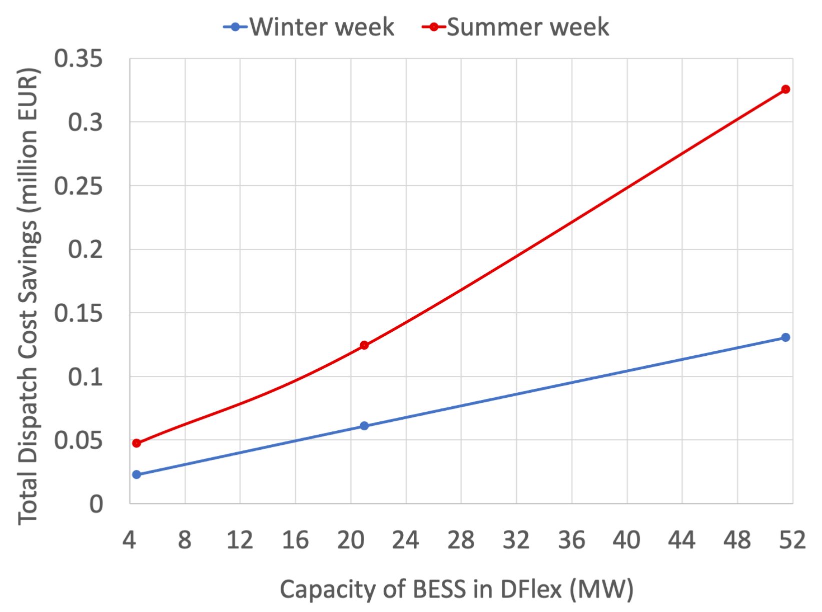
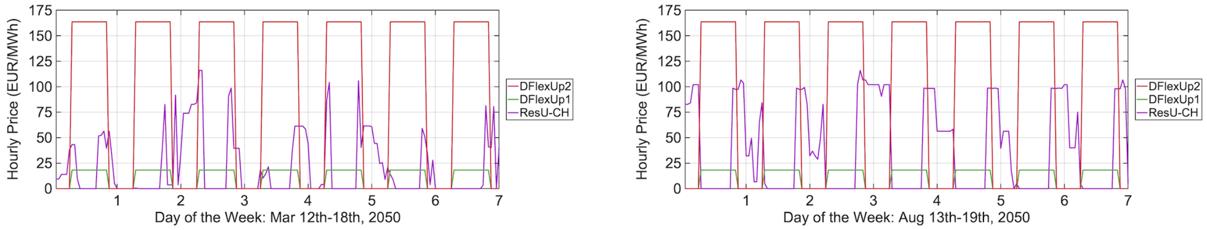


Figure 31: Scaling BESS penetration: The dispatch cost saving benefits of utilizing DFlex scales up smoothly with the increasing capacity of BESS in DFlex.

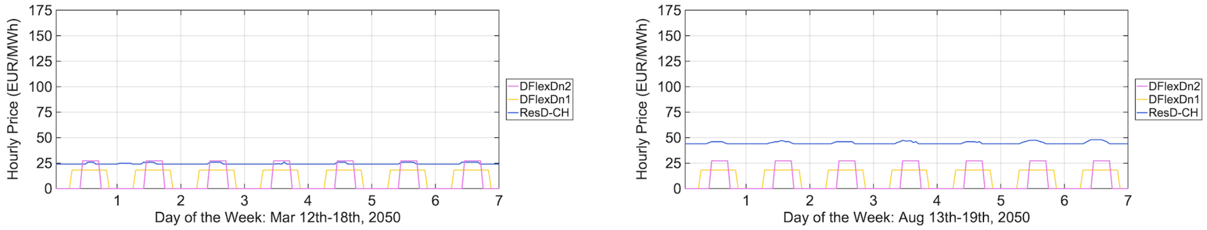
Changes to the consumer tariff levels As discussed in Section 2.3, the remuneration scheme for most of the flexibility contributions that make up DFlex is connected to the consumer's retail tariff structure and in this investigation is assumed to be the Δ Tariff, or the difference between the tariff at the time of flexibility provision and the minimum tariff. Utilizing a 2-tier tariff structure, the resulting Δ Tariff is either equal to zero (during all low-tariff hours) or to the difference between the high-tariff *HT* and the low-tariff *LT* (i.e., Δ Tariff = $HT - LT$). Since there is uncertainty about how the tariff structure as well as the tariff values will evolve in the future, two scenarios are created to illustrate the sensitivity to the use of DFlex when the Δ Tariff is lower (s4 as 'Low Δ Tariff') or higher (s5 as 'High Δ Tariff') than the base scenario. The difference between high and low tariffs in the base scenario (i.e., 'High Δ Tariff') is 50 EUR, while the difference is 30 EUR and 80 EUR in the 'Low Δ Tariff' and 'High Δ Tariff' scenarios, respectively. Since the Δ Tariff level does not impact the amount of available power capacities from DFlex, the power availability plots will be the same as in the 'High BESS' scenario and are not shown here.

Figure 32 compares the reserve prices with those of DFlex and Figure 33 shows the resulting Swiss reserve procurements including from DFlex for the scenario with a low Δ Tariff. Similarly, Figure 34 compares the reserve prices with those of DFlex and Figure 35 shows the resulting Swiss reserve procurements including from DFlex for the scenario with a high Δ Tariff.



(a) Upward reserve and DFlex prices - Winter

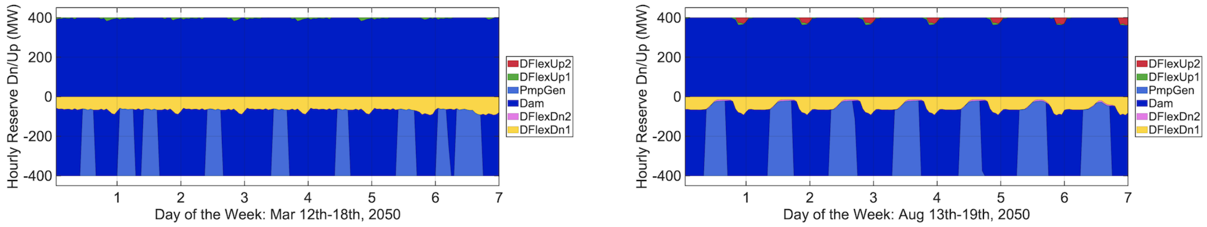
(b) Upward reserve and DFlex prices - Summer



(c) Downward reserve and DFlex prices - Winter

(d) Downward reserve and DFlex prices - Summer

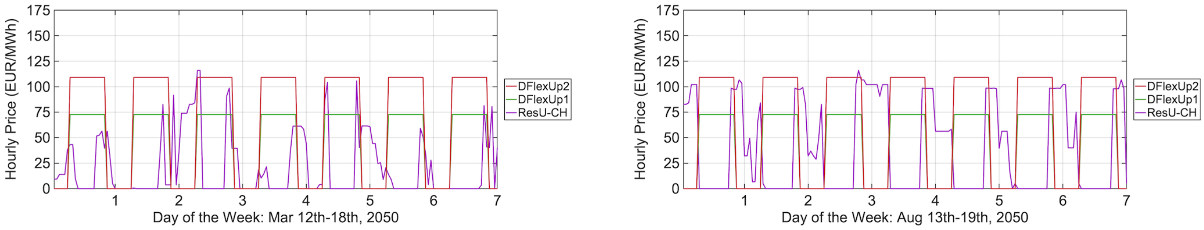
Figure 32: Low Δ Tariff: Upward reserve and DFlex prices (top row) and downward reserve and DFlex prices (bottom row).



(a) CH Reserve Procurement - Winter

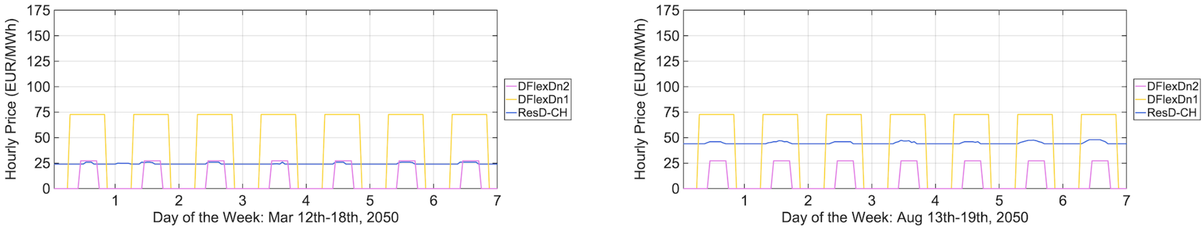
(b) CH Reserve Procurement - Summer

Figure 33: Low Δ Tariff: Reserve procurement for Switzerland.



(a) Upward reserve and DFlex prices - Winter

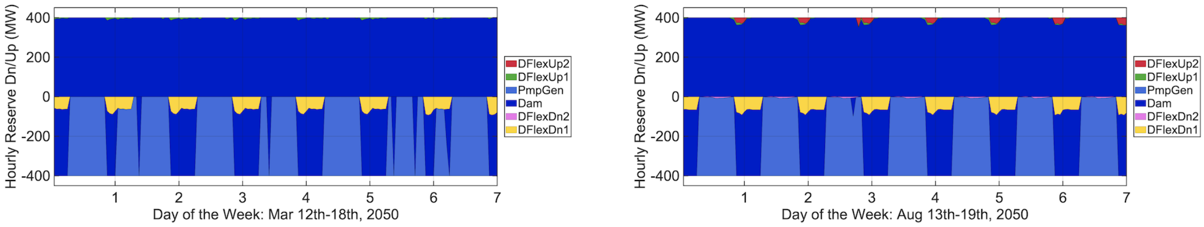
(b) Upward reserve and DFlex prices - Summer



(c) Downward reserve and DFlex prices - Winter

(d) Downward reserve and DFlex prices - Summer

Figure 34: High Δ Tariff: Upward reserve and DFlex prices (top row) and downward reserve and DFlex prices (bottom row).



(a) CH Reserve Procurement - Winter

(b) CH Reserve Procurement - Summer

Figure 35: High Δ Tariff: Reserve procurement for Switzerland.

The changing Δ Tariff influences the offer prices for all non-PV components of DFlex (i.e., DFlexUp1, DFlexUp2, DFlexDn1). In the 'Low Δ Tariff' scenario, the changed prices lead to DFlexDn1 being more often competitive with more hours of reserve down procurement. At the same time, the prices for DFlexUp1 also improve but the impact is minimal since the amount of available power is so small and the the prices for DFlexUp2 become worse. Alternatively, in the 'High Δ Tariff' scenario, the prices for DFlexUp2 improve while those of DFlexUp1 and DFlexDn1 become worse. However the impacts in this case are more minimal since little capacity is procured from DFlexUp2. Figure 36 illustrates how the savings develop as Δ Tariff changes for the components of DFlex from a low of 30 EUR to a high of 80 EUR. The savings scale up as the Δ Tariff reduces. Over the two weeks of the 'Low Δ Tariff' scenario, the use of DFlex for reserves achieves a savings of nearly 600'000 Euro.

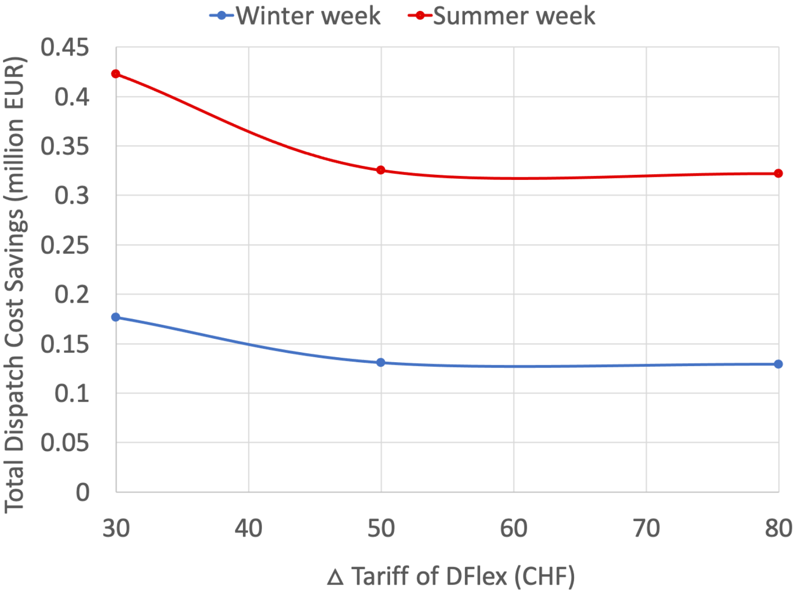
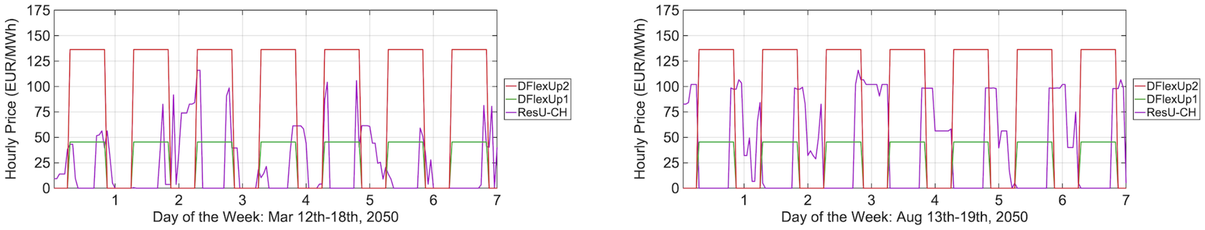


Figure 36: Scaling Δ Tariff: The dispatch cost saving benefits of utilizing DFlex scales up as the Δ Tariff reduces for the DFlex components.

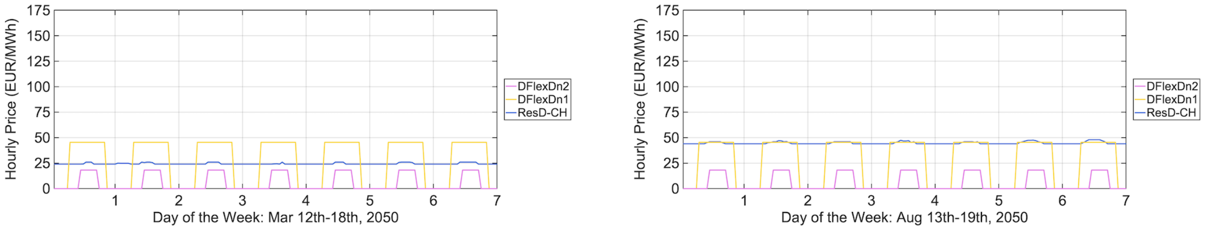
Changes to the consumer feed-in price Similar to the influence of the retail tariff values, the feed-in price paid for injections into the local distribution grid determine the necessary remuneration for curtailments of PV. Since there is uncertainty about how this price will evolve in the future, two scenarios are created to illustrate the sensitivity to the use of DFlex when the feed-in price is lower (s6 as 'Low Feed-In') or higher (s7 as 'High Feed-In') than the base scenario. The value of the feed-in in the base scenario (i.e., 'Med Feed-In') is 30 EUR/MWh, while the value is 20 EUR/MWh and 50 EUR/MWH for the 'Low Feed-In' and 'High Feed-In' scenarios, respectively. Since the feed-in price level does not impact the amount of available power capacities from DFlex, the power availability plots will be the same as in the 'High BESS' scenario and are not shown here.

Figure 37 compares the reserve prices with those of DFlex and Figure 38 shows the resulting Swiss reserve procurements including from DFlex for the scenario with a low feed-in price. Similarly, Figure 39 compares the reserve prices with those of DFlex and Figure 40 shows the resulting Swiss reserve procurements including from DFlex for the scenario with a high feed-in price.

The changing feed-in price only influences the offer prices for the PV components of DFlex (i.e., DFlexDn2). A higher feed-in price increases the DFlexDn2 price while a lower feed-in decreases the DFlexDn2 price. Since the amount of available power from PV was small, there is little noticeable differences in these results when compared to the 'High BESS' scenario. The cost savings benefits for the two alternative feed-in scenarios (i.e., 'Low Feed-In' and 'High Feed-In') achieve a savings equal to that of the base 'Med Feed-In' scenario, which was just over 450'000 EUR for the two simulated weeks combined.

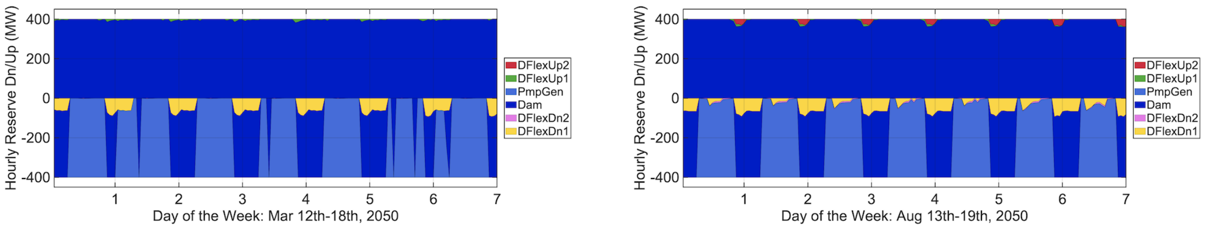


(a) Upward reserve and DFlex prices - Winter (b) Upward reserve and DFlex prices - Summer



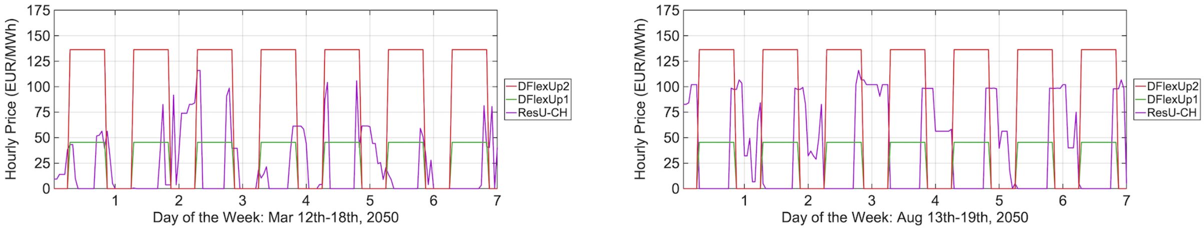
(c) Downward reserve and DFlex prices - Winter (d) Downward reserve and DFlex prices - Summer

Figure 37: Low Feed-In: Upward reserve and DFlex prices (top row) and downward reserve and DFlex prices (bottom row).

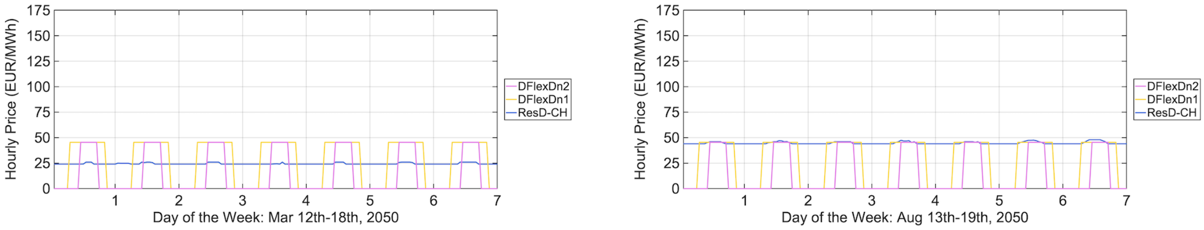


(a) CH Reserve Procurement - Winter (b) CH Reserve Procurement - Summer

Figure 38: Low Feed-In: Reserve procurement for Switzerland.

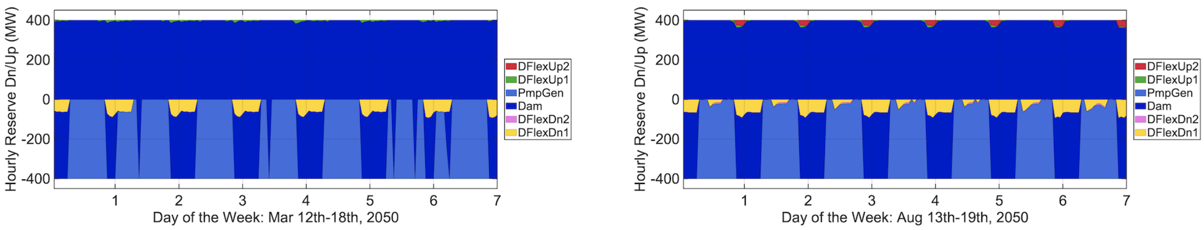


(a) Upward reserve and DFlex prices - Winter (b) Upward reserve and DFlex prices - Summer



(c) Downward reserve and DFlex prices - Winter (d) Downward reserve and DFlex prices - Summer

Figure 39: High Feed-In: Upward reserve and DFlex prices (top row) and downward reserve and DFlex prices (bottom row).



(a) CH Reserve Procurement - Winter (b) CH Reserve Procurement - Summer

Figure 40: High Feed-In: Reserve procurement for Switzerland.

4.2.4 Sensitivities: international trends

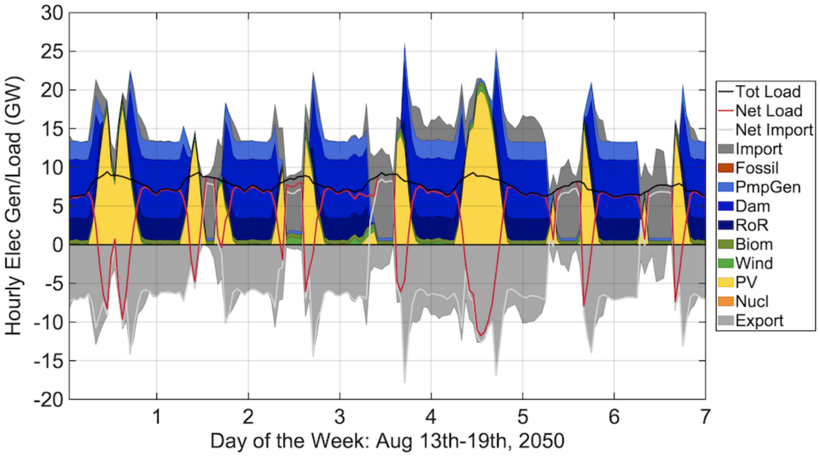
The sensitivities in this section are aimed at some very relevant system conditions that have high uncertainties for their development until 2050, namely: the possibility that the Swiss energy market may face starkly lower or higher limits on its net transfer capacity, the possibility of natural gas prices increasing much faster than the projections from ENTSO-E, and the possibility that the penetration levels of RES fall far short of the goals in the Global Ambition scenario of the 2020 TYNDP.

The results will show that as the Swiss NTC is more restricted, the production mix shifts to focus on supplying Switzerland instead of exporting; however, this change has only a minor impact on the use of DFlex for reserves; a high price of natural gas leads to increasing market prices and greater utilization of DFlex for upward reserves, but the gains are minor compared to the use of DFlex for downward reserves; a lack of development toward the desired RES penetration levels leads to significant increases in the use of other conventional generators across all five countries but does not significantly alter the use of DFlex, which is still most prominently utilized for downward reserves.

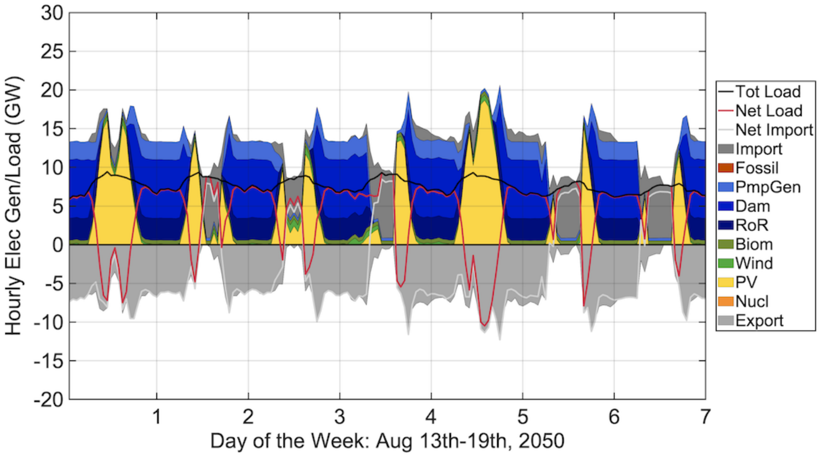
Changes to the Swiss NTCs The upcoming enforcement of the ENTSO-E's 70% rule for market transfer capacities is currently at the forefront of discussions in Switzerland based on the potential impact it could have on the Swiss electricity market. While there is broad uncertainty about exactly what the new rule would require, there is a general consensus that it will require the use of significantly lower NTC limits for the Swiss borders. Such a change could drastically alter the amount of energy trading between Switzerland and its European neighbors, in effect forcing Switzerland to be much more self-reliant and vulnerable to both security of supply and network security issues. To investigate how such a change could alter the impacts of the use of DFlex for reserves, we create two alternative scenarios for the Swiss NTC limits. First, the reduced Swiss NTC scenario s8 ('Reduced CH NTC') enforces cross-border power flow limits that are one-third the current 2050 NTC projections. This case aims to represent the possible impact of the ENTSO-E 70% rule. Alternatively, it is also useful to understand how the use of DFlex changes under a general relaxing of the Swiss cross-border limits. Hence the expanded Swiss NTC scenario s9 ('Expanded CH NTC') increases the cross-border limits to equal the sum of the full transmission grid limits, also known as the GTC. Since the Swiss NTC limits do not impact the amount of available power capacities from DFlex nor the remuneration of DFlex, the power availability plots and the upward and downward price plots will be the same as in the 'High BESS' scenario and are not shown here (only the upward reserve price will change in the upward prices plot as it continues to follow the energy price).

Figure 41 compares the electricity dispatch for Switzerland for the 'Expanded' (GTC), 'Current' (NTC) and 'Reduced' ($^1\!/\!_3$*NTC) scenarios. Figure 42 illustrates the impact that the change in trading capabilities has on the Swiss electricity and reserve prices. Figure 43 shows the resulting Swiss reserve procurements including from DFlex for the three scenarios. In these figures, only the summer week results are shown since the total DFlex utilization is higher and the impacts are also representative of the winter week.

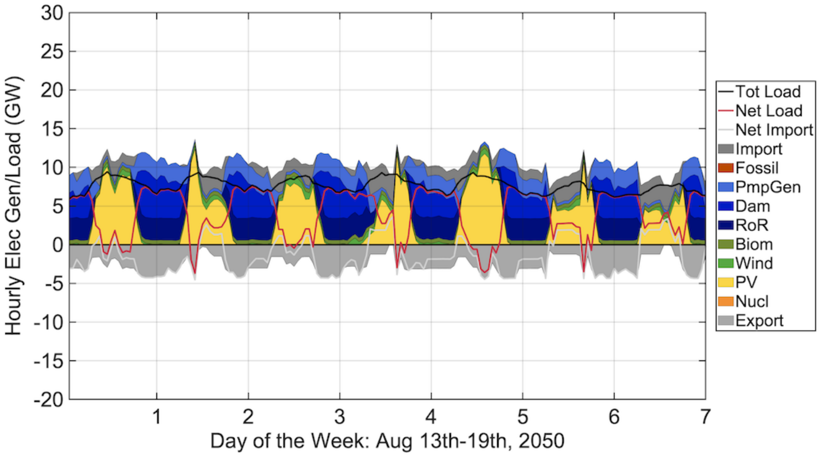
The relaxing or restricting of the Swiss NTC limits has a significant effect on the dispatch and in particular on the ability to export the Swiss hydro and PV production. As the transfer limit shrinks, so too does the magnitude of exports and the production from Swiss PV. In fact, significantly more PV curtailments are needed in the most restrictive case since there is nowhere for the electricity to go. Overall, the more restrictive NTC forces the Swiss production pattern to be more directly tied to the Swiss demand. The Swiss energy and reserve prices respond by becoming more influenced by the neighboring countries as the NTC increases and more trading occurs (i.e., prices increase) while for the restricted case, the Swiss prices instead are more reflective of the Swiss generators operating costs (i.e., prices decrease). While this result may seem counter intuitive (less restriction should lead to lower costs and prices); the explanation is that these are only the Swiss prices and while they increase with less



(a) CH Generation - GTC

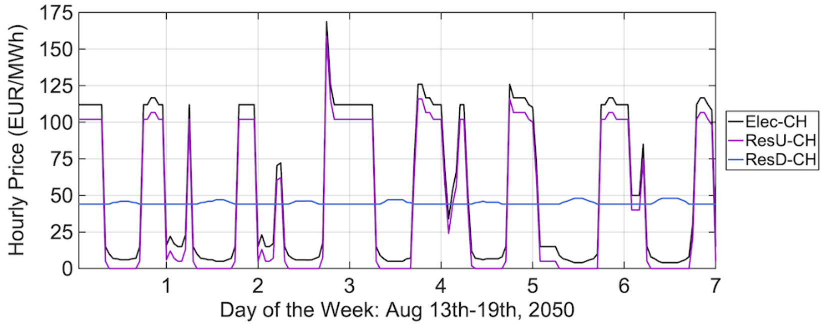


(b) CH Generation - NTC

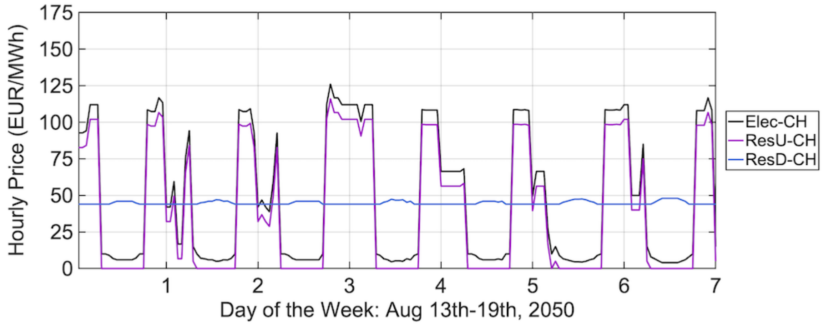


(c) CH Generation - $^1/_3$*NTC

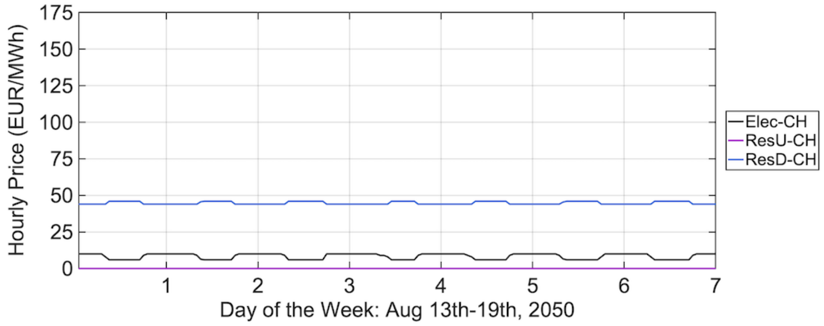
Figure 41: Changing Swiss NTCs: electricity production by generator type for Switzerland.



(a) CH Prices - GTC



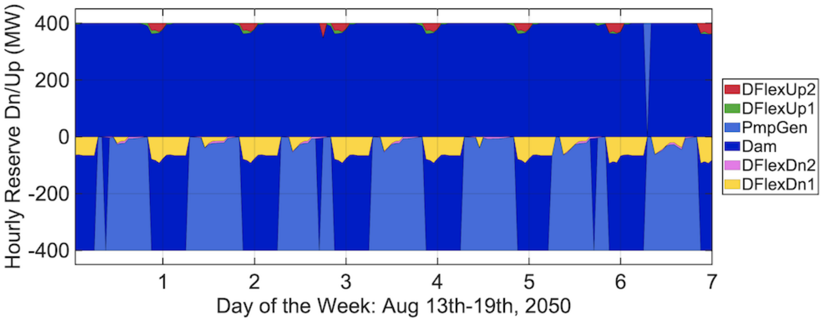
(b) CH Prices - NTC



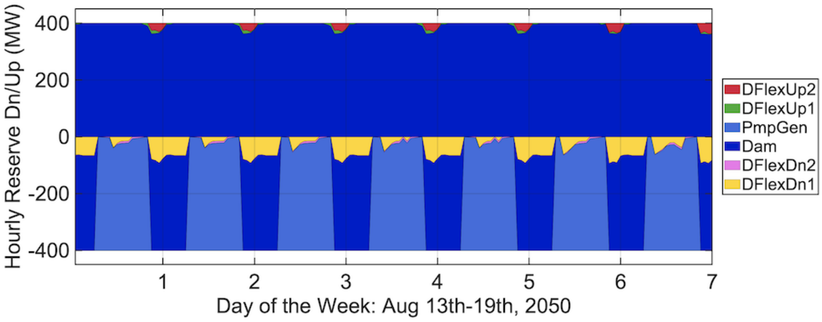
(c) CH Prices - 1/3*NTC

Figure 42: Changing Swiss NTCs: electricity and reserve prices for Switzerland.

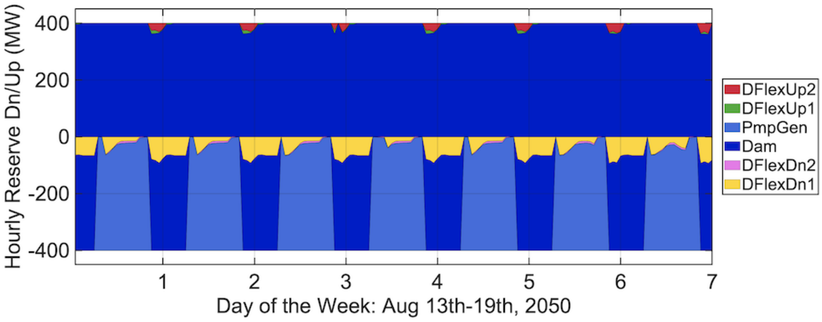
restrictions, the overall system costs go down as restrictions reduce and prices in other market zones also go down. In fact, the total dispatch cost of the less restrictive GTC scenario is 6.5% (21%) cheaper in the summer (winter) week than the NTC scenario; while the more restrictive 1/3*NTC scenario is 14.5% (19.4%) more expensive in the summer (winter) week than the NTC scenario. The impact on the utilization of DFlex is actually quite small since the majority of procured reserves are from DFlexDn1 and the changes to the energy prices do not impact the downward reserve prices much. As the grid restriction increases, a small increase in use of DFlexDn1 can be observed during the afternoons. However minor the impact on the use of DFlex is, factors that yield significant changes to the Swiss energy prices could push the reserve prices above the DFlex prices at times they were otherwise not and therefore the influence of these factors should be considered.



(a) CH Reserve Procurement - GTC



(b) CH Reserve Procurement - NTC

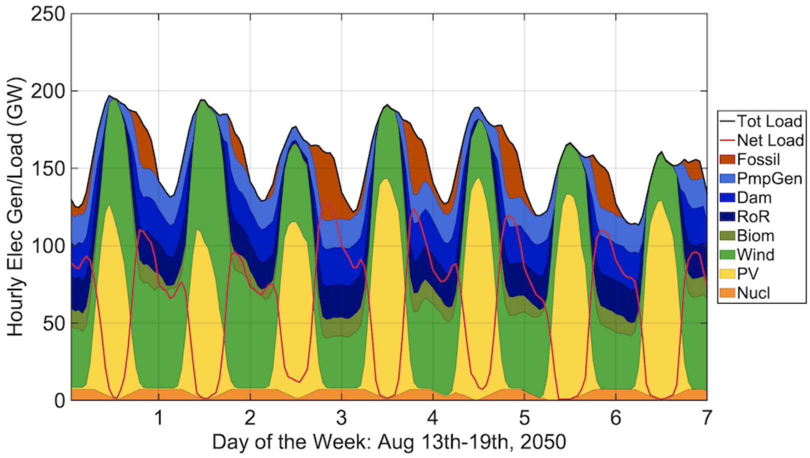


(c) CH Reserve Procurement - $^1/_3$*NTC

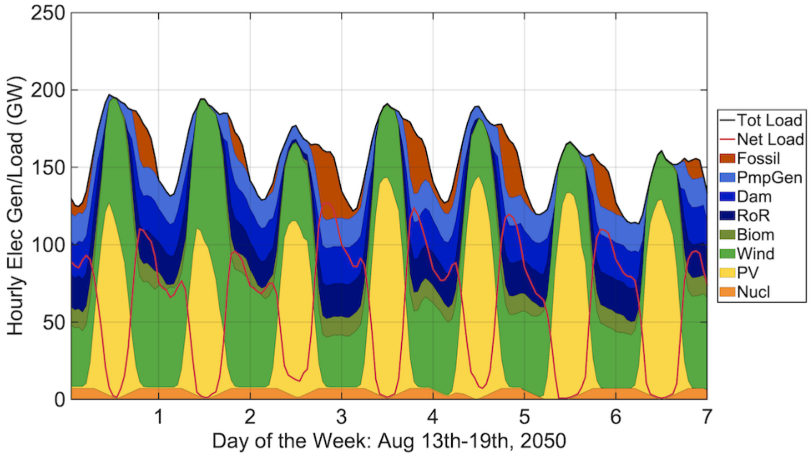
Figure 43: Changing Swiss NTCs: Reserve procurement for Switzerland.

Increasing the Swiss and EU gas prices While the wholesale price of natural gas in Europe has been quite stable and low over the last decade (highs of around 30 EUR/MWh-thermal), the prices in the second half of 2021 took a remarkable turn and skyrocketed to values consistently above 60 EUR/MWh with highs of over 170 EUR/MWh. Therefore, it is important to understand how different the overall system behaves and how different the impact of DFlex are for a future with much higher natural gas prices. Since this unexpected change was not represented in the projections of the ENTSO-E used for this study, an alternative scenario was created s10 ('High Gas Price') with a European gas price three times higher than the ENTSO-E projections [12] and a Swiss gas price two times higher than the SFOE sponsored studies [19, 20]. Since the natural gas prices do not impact the amount of available power capacities from DFlex nor the remuneration of DFlex, the power availability plots and the upward and downward price plots will be the same as in the 'High BESS' scenario and are not shown here (only the upward reserve price will change in the upward prices plot as it continues to follow the energy price).

Figures 44 and 45 compare the electricity dispatch for the central EU region and for Switzerland, respectively, for the base scenario (gas price as projected by [12, 19]) and the 'High Gas Price' scenario. Figure 46 illustrates the impact that the increase in natural gas price has on the Swiss electricity and reserve prices. Figure 47 shows the resulting Swiss reserve procurements including from DFlex for the two scenarios. In these figures, only the summer week results are shown since the total DFlex utilization is higher and the impacts are also representative of the winter week.



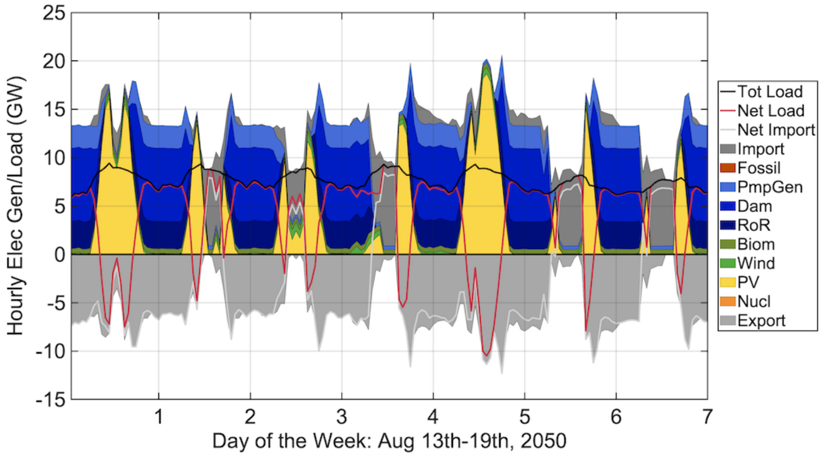
(a) EU Generation - Gas as projected



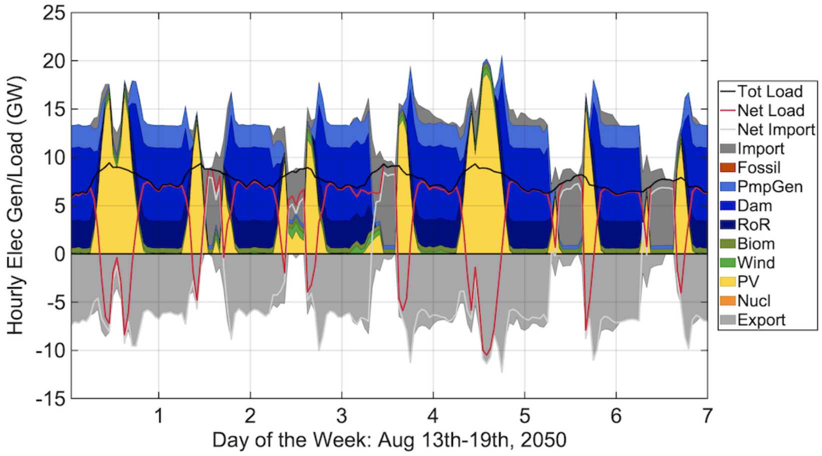
(b) EU Generation - Gas high

Figure 44: Increasing Gas Price: electricity production by generator type for central EU region.

While it is difficult to see in the EU generation plot, the increase in the price of natural gas shifts some production away from gas generators in favor of electricity from mainly biomass units. Similarly, the impacts of the higher gas price on the Swiss supply is almost negligible since no gas generators are used in either case. Where the impact of an increasing gas price can clearly be seen is on the prices of energy and upward reserves. Since gas is at times the marginal generator in several of the European countries simulated, the wholesale electricity prices are much higher during peak price times than they were in the base 'High BESS' scenario. And while increasing prices do lead to more potential for DFlex as a provider of upward reserves (doubling procurements of DFlexUp2 in summer), the gains are minor compared to the utilization of DFlex for downward reserves. Once again, this system change leading to higher energy and reserve prices has little impact on DFlex.

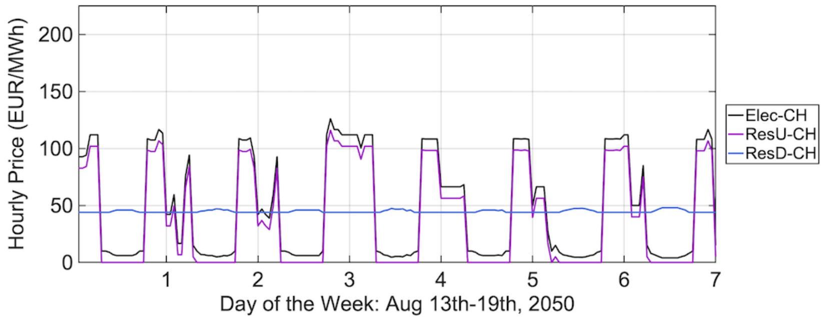


(a) CH Generation - Gas as projected

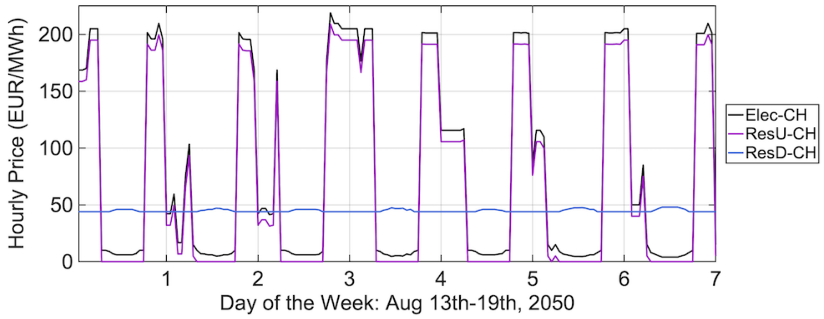


(b) CH Generation - Gas high

Figure 45: Increasing Gas Price: electricity production by generator type for Switzerland.

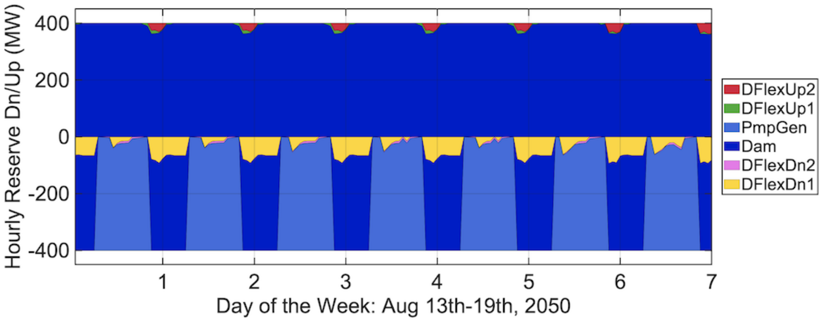


(a) CH Prices - Gas as projected

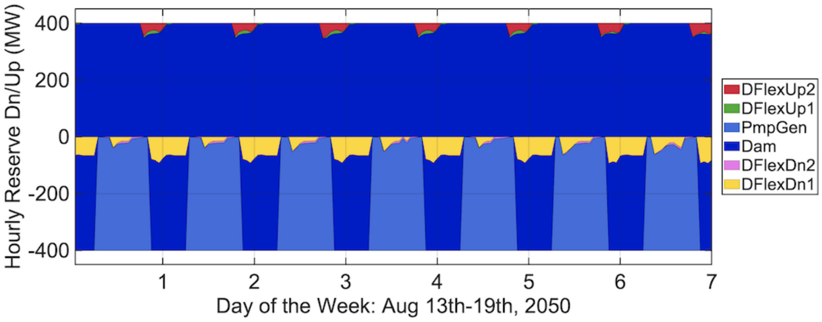


(b) CH Prices - Gas high

Figure 46: Increasing Gas Price: electricity and reserve prices for Switzerland.



(a) CH Reserve Procurement - Gas as projected



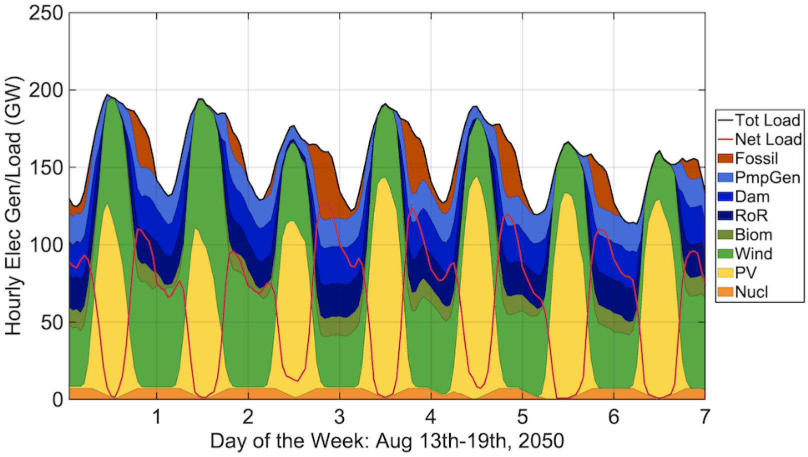
(b) CH Reserve Procurement - Gas high

Figure 47: Increasing Gas Price: Reserve procurement for Switzerland.

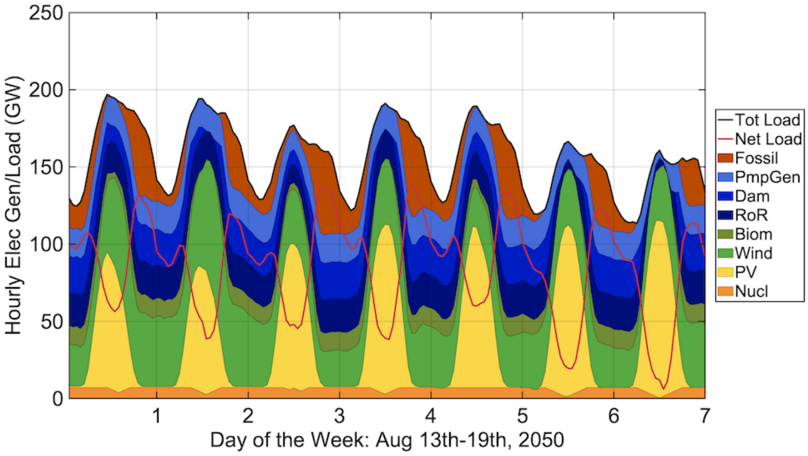
Reducing the Swiss and EU RES penetration The ENTSO-E's TYNDP Global Ambition scenario goes a bit beyond the current European national pledges for integration of RES. However, the ability for countries to meet these objectives is highly questioned and many countries are already lagging behind the progress stated in their pledges. The scenario s11 ('Low RES') reduces the achieved wind and PV capacities in 2050 by 30% compared to the projections in the Global Ambition scenario. This alternative would require more use of conventional capacities that tend to be higher cost, potentially leading to higher energy and reserve prices that could increase the benefits achieved with DFlex. Since the RES penetration level does not impact the amount of available power capacities from DFlex nor the remuneration of DFlex, the power availability plots and the upward and downward price plots will be the same as in the 'High BESS' scenario and are not shown here (only the upward reserve price will change in the upward prices plot as it continues to follow the energy price).

Figures 48 and 49 compare the electricity dispatch for the central EU region and for Switzerland, respectively, for the base scenario (RES as projected by [12, 18]) and the 'Low RES' scenario. Figure 50 illustrates the impact that the decrease in RES production has on the Swiss electricity and reserve prices. Figure 51 shows the resulting Swiss reserve procurements including from DFlex for the two scenarios. In these figures, only the summer week results are shown since the total DFlex utilization is higher and the impacts are also representative of the winter week.

Unlike the previous system changes, the reduction in available RES production causes clear changes to the production mix of both the central EU region and Switzerland. The loss of these RES injections represents a loss of around 16% of all generation within the five countries and a loss of around 8% for Switzerland itself. This massive loss is compensated by increasing use of every other European generator type, especially hydro and gas-fired units. In Switzerland, while the peak of the PV production is lower, there is actually more production from PV during several afternoons when previously Swiss PV was being curtailed in favor of cheaper imports. These changes also impact the Swiss energy and reserve prices, leading to an increase in the number of hours where prices are high (i.e., set by gas generators). However, the magnitude of the peak prices stays the same and the prices remain low during the same sunny afternoon hours when PV, wind, and hydro are the source of supply. Once again, while the energy and upward reserve prices do increase, only minor impacts are observed on the use of DFlex.

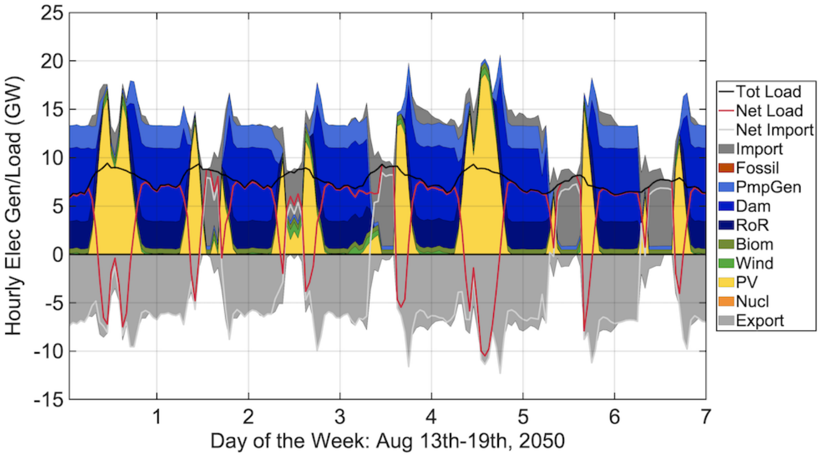


(a) EU Generation - RES as projected

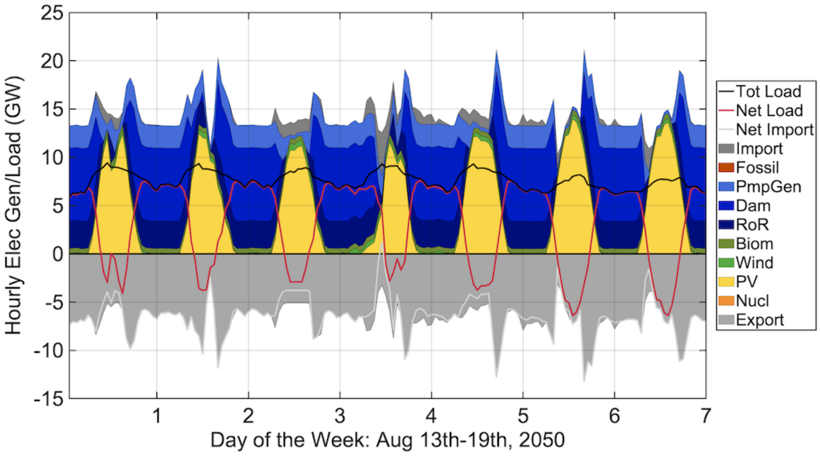


(b) EU Generation - Low RES

Figure 48: Reducing RES: electricity production by generator type for central EU region.

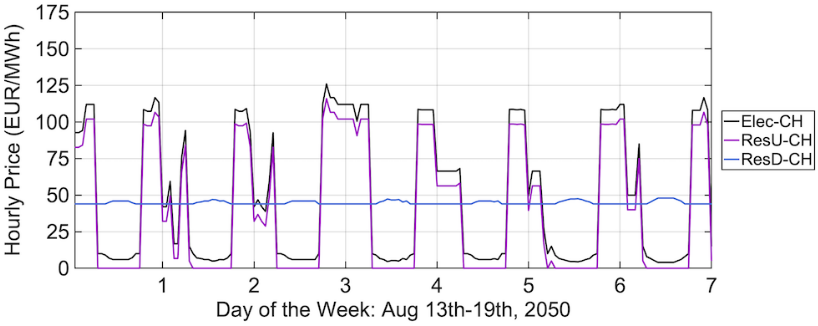


(a) CH Generation - RES as projected

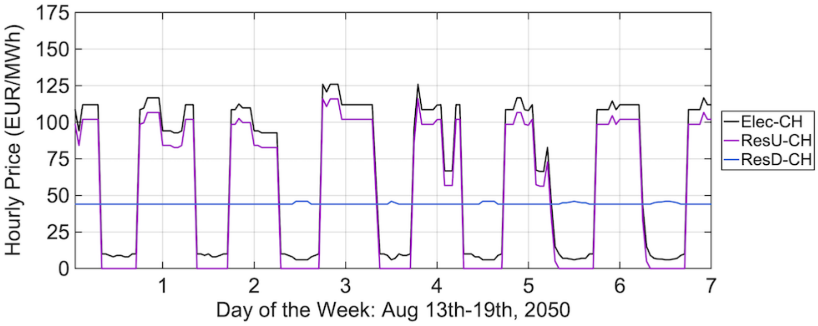


(b) CH Generation - Low RES

Figure 49: Reducing RES: electricity production by generator type for Switzerland.

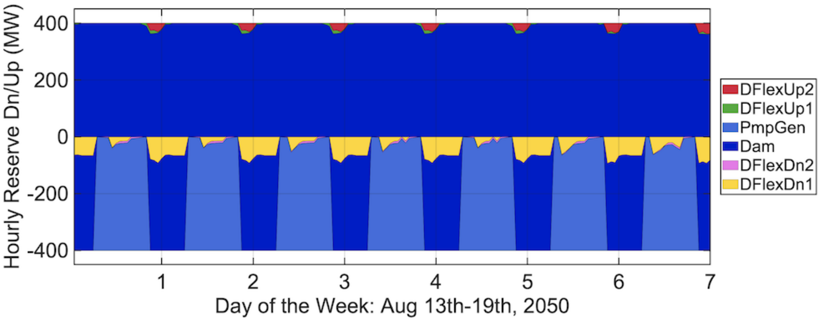


(a) CH Prices - RES as projected

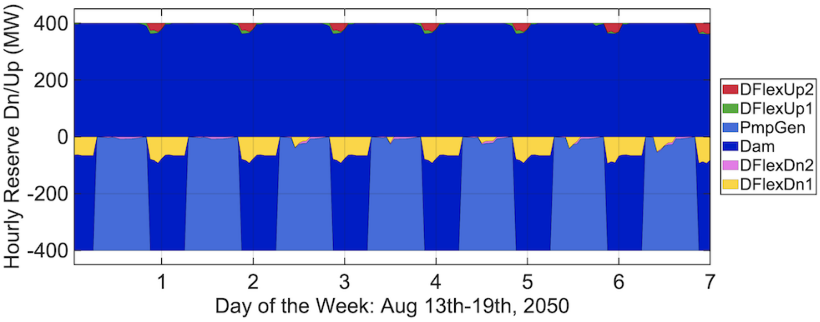


(b) CH Prices - Low RES

Figure 50: Reducing RES: electricity and reserve prices for Switzerland.



(a) CH Reserve Procurement - RES as projected



(b) CH Reserve Procurement - Low RES

Figure 51: Reducing RES: Reserve procurement for Switzerland.

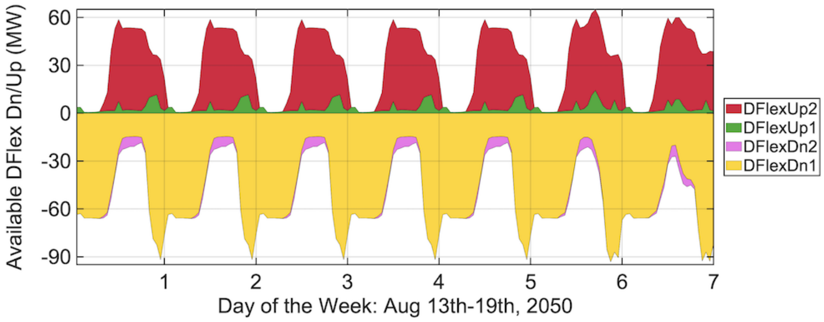
4.2.5 Scaling impacts

The results discussed so far have shown the benefits of using DFlex for capacity reserves along with a number of important sensitivities that influence the scale of those benefits. In all cases, the DFlex unit was represented by an aggregation of 50 participating communities with a maximum potential for offering positive and negative reserves of 65 MW and 93 MW, respectively. To understand how the benefits scale as more communities decide to participate, two additional scenarios are created. First, s12 ('High Participants') doubles the offered power capacities by representing 100 communities, and the second s13 ('Very High Participants') represents 400 participating communities (enough to supply the entire Swiss reserve requirement at present). Since the number of communities does not impact the remuneration of DFlex, the upward and downward price plots will be the same as in the 'High BESS' scenario and are not shown here.

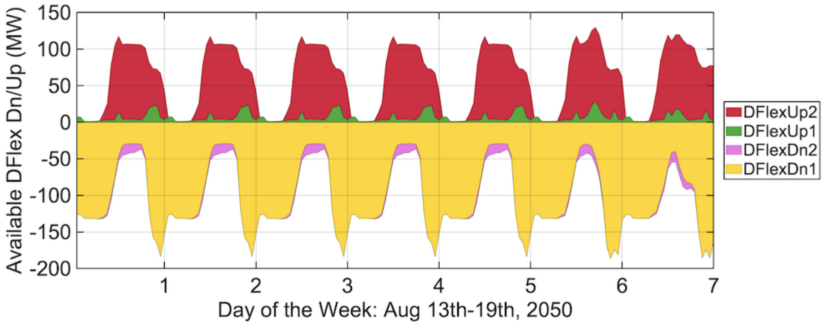
The results will show that scaling up the number of communities directly increases the utilization of DFlex for both upward and downward reserves, leading to the outcome that DFlex at times provides all the required downward reserves (and over two-thirds of the upwards reserves). At the highest scale of 400 communities, the use of DFlex for reserves achieves a savings of the system dispatch costs of over 2.8 million Euro over the two weeks combined.

Figure 52 compares the positive and negative power available from DFlex as the number of participating communities scales up from 50 to 100 to 400. Figure 53 illustrates the resulting Swiss reserve procurements including from DFlex for these three scenarios.

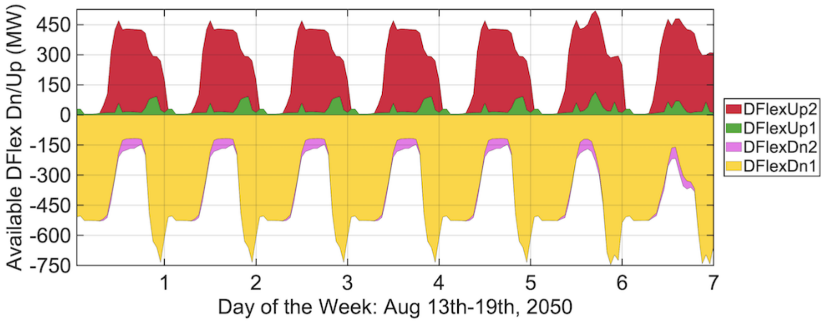
The increasing number of participating communities scales up the available positive and negative active power that DFlex can offer into the reserve market. At the highest level, DFlex can at times offer over 400 MW of positive or negative capacity, enabling it to potentially provide the entire required reserves for the Swiss market. This potential does become a reality as the DFlexDn1 unit provides the full 400 MW of downward reserves in many of the summer hours shown. Additionally, for the first time, DFlex becomes a significant contributor to the upward reserve requirement, providing over two-thirds of the total requirement in a few hours. The scaling up of the DFlex potential and resulting procurement also has an impact on the system total dispatch costs. Figure 54 illustrates how the savings develop as the number of communities scales up. The savings scale up smoothly with the number of communities, with only a small apparent diminishing return. Over these two weeks, the use of DFlex for reserves achieves a savings of over 2.8 million Euro.



(a) DFlex power available - 50 communities

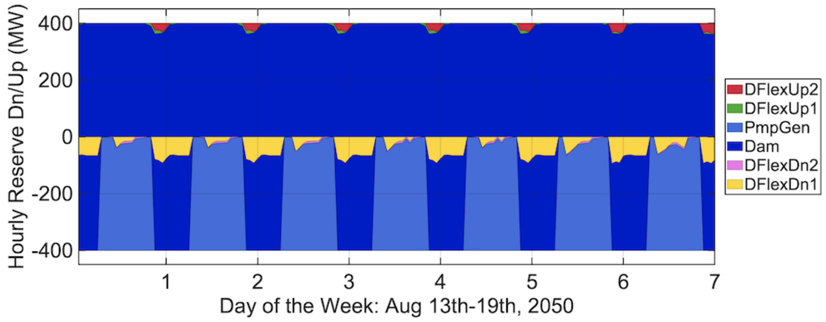


(b) DFlex power available - 100 communities

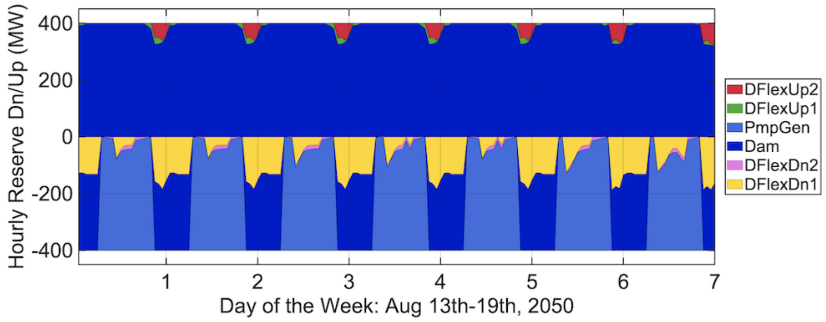


(c) DFlex power available - 400 communities

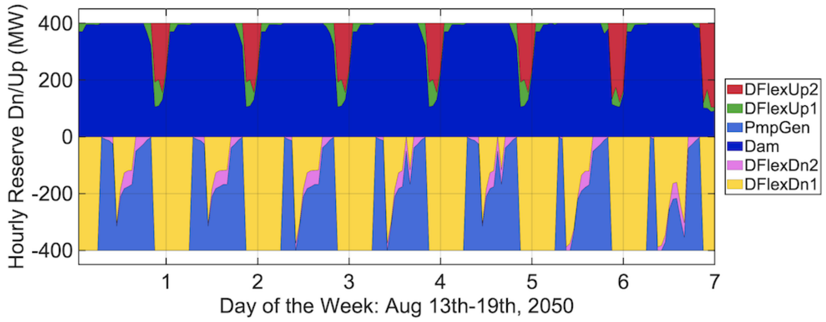
Figure 52: Scaling up DFlex communities: positive and negative active power available from DFlex.



(a) CH Reserve Procurement - 50 communities



(b) CH Reserve Procurement - 100 communities



(c) CH Reserve Procurement - 400 communities

Figure 53: Scaling up DFlex communities: Reserve procurement for Switzerland.

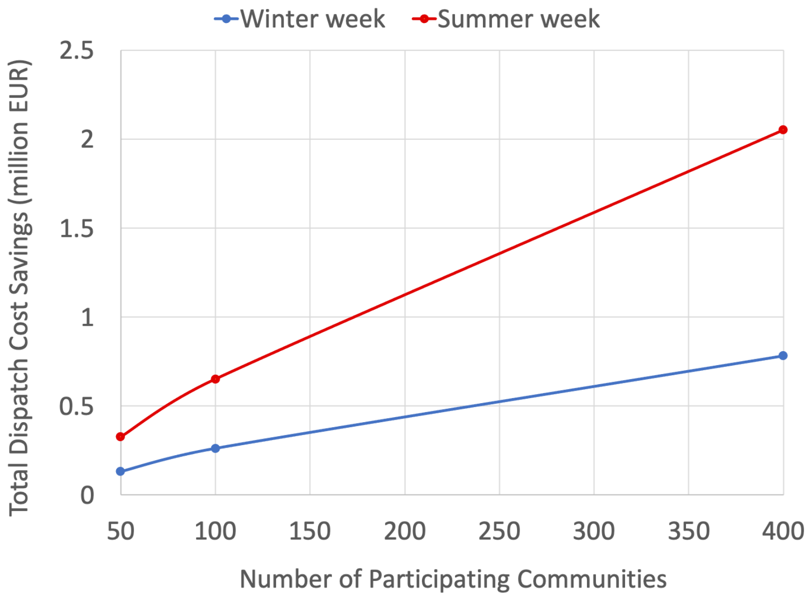


Figure 54: Scaling up DFlex communities: The dispatch cost saving benefits of utilizing DFlex scales up smoothly with the increasing number of participating communities.

4.3 Discussion

The aggregated flexibilities of the components that make up the represented DFlex unit (conventional load, HPs, EVs, PV, and BESS) have the potential to provide services to the electricity market through offering their flexible active power capability (positive and negative) as a capacity reserve in Switzerland. To investigate the economic attractiveness and utilization impact of DFlex for providing reserves, a time-coupled economic dispatch co-optimization model of the energy and reserve markets was applied to a number of scenarios covering different DFlex component conditions and different international system conditions.

In the base 'High BESS' scenario, out of the four components that make up the modeled DFlex unit, the two that are associated with BESS are shown to dominate the power availability (”DFlex Down Group 1”: only BESSs and ”DFlex Up Group 2”: BESSs, PVs, HPs, EVs, conventional demand), making it clear that BESS is the most crucial component for creating a flexible asset out of the combination of many distributed resources. Based on the conjunction of these power availabilities with the offer prices that result from the remuneration scheme, it is clear that the ”DFlex Down Group 1” component has the greatest potential for reserve procurements because it is the only component that has significant available power during hours when it price is below the reserve price.

DFlex is procured as a reserve during any hour when its offer price is below the reserve clearing price and the impact of procuring DFlex for reserves is consistent across all simulated scenarios. The use of DFlex for upward reserves relieves hydro capacities, which in turn produce more energy in place of other more expensive generators, leading to lower total dispatch costs. Alternatively, the use of DFlex for downward reserves generally does not have a direct impact on the dispatch costs, except during hours when Swiss generators are curtailed in favor of cheaper imports. At these times a small amount of Swiss hydro units are online solely to provide the required downward reserves and the procurement of downward DFlex capacity at such an hour allows less must-run use of these hydro units and leads to lower total dispatch costs.

The remuneration scheme is a critical assumption in this assessment since it has the most direct influence on when DFlex capacities are cost competitive. In this work, the bulk of all procurements from DFlex occur during hours when the offer price is zero. This is also the reason so little upward DFlex capacity is procured since during most of the zero price hours DFlex has little or no available upward power capability. While this work applies specific remuneration schemes for the four DFlex components, the general message is that most offer prices (both high and low) are in close range of the reserve prices and different remuneration schemes would likely fall into this same range, where DFlex capacities are shown to be competitive and provide useful system benefits.

The sensitivity of these benefits to the amount of BESS within the DFlex community clearly shows that a reduction in the size of BESS directly reduces the amount of available power as well as resulting procured power from DFlex. However, both sensitivities assessed involving the offer prices (i.e., ∆ Tariff and Feed-In) reveal only minor changes to the procurements and benefits of DFlex since they do not noticeable alter the economic attractiveness of the ”DFlex Down Group 1” component (conventional load, HPs, EVs, and BESS).

Beyond the local composition and remuneration of DFlex, system-wide aspects could also influence the competitiveness and benefits of DFlex. While the Swiss and wider European system dispatch was clearly sensitive to restrictions on the market NTCs, the price of natural gas, and the level of RES integration achieved, all three system aspects had little effect on the use and benefits of DFlex for reserves. Overall, the influence of the remuneration scheme is more influential than the changes in the system-wide conditions.

Scaling up the quantity of communities participating and therefore the associated available power flexibility of DFlex leads to proportional increases in the system dispatch cost savings. When scaled up enough, DFlex was found at times to provide the entire downward reserve requirement as well as around two-thirds of the upward reserve requirement. At this level, the utilization of DFlex for reserves yielded a cost savings of over 2.8 million Euro for the two simulated weeks combined.

5 Flexibility for transmission operation

This section presents how the utilization of aggregated DER flexibilities at the TSO-DSO substations can benefit the operation of the power system. The demonstration of the benefit is designed around a central question for the Swiss transmission system adequacy assessment: How much local production (from Swiss nuclear and hydro generation) is required when the transmission grid reaches its import capacity limits? This translates to a minimum storage level requirement on the Swiss hydro reservoirs, that has become known as ”Winterreserve” during the winter months. It will be shown for hourly full year assessments, how the flexibility provided by the aggregated DER can impact and relieve this requirement. The DER-flexibility can increase the energy import from North (i.e., France, Germany and Austria) to cover Swiss demand and the energy export to the South, thereby reducing the requirement for local production and minimum water levels of the hydro dam reservoirs.

The activities described in this section cover the operation-related tasks in **Step 4** in Figure 1. The remainder of this operation assessment section includes: the details of the methodology in Section 5.1, illustrative results in Section 5.2 followed by the discussion including take-away messages in Section 5.3.

5.1 Methodology

5.1.1 Overview of the Methodology

Transmission system operators perform optimal energy dispatch day-ahead as well as intra-day on an hourly or sub-hourly basis, to ensure the energy balance while minimizing the cost of energy, and respecting the grid constraints in the meantime. In order to demonstrate the benefit from aggregated flexibilities provided by the DERs, we emulate the system operation using reference time series for operational scenarios of the Swiss transmission grid. However, we seek to determine the minimum local production level for grid security. Consequently, the chosen objective is the minimization of the power generation by hydro dams at each hour, while maximizing the energy imports from north, using AC optimal power flow. Figure 55 shows the overall operation benefit framework. The approach consists of three steps, which are performed consecutively for the selected input scenarios.

1. Identification of **general** hydro dam generation requirements in Switzerland to satisfy the grid constraints for sampled combinations of Swiss demand and net export energy to Italy, including the boundary combinations.
2. Identification of **hourly** hydro dam generation requirements using an interpolation process based on hourly reference time series of Swiss demand and export to IT and the results of the first step.
3. Estimation of the corresponding **monthly** hydro dam water level requirements to allow the required hydro dam generation computed in the second step.

5.1.2 Assumptions of the AC OPF model

The core of the methodology to assess the impact of DER-flexibility on the transmission system operation is the AC OPF model, used to determine the general hydro dam generation requirements.

The network model uses the 2025 Swiss high voltage network also described in Section 2.1. Each of the four neighboring countries is represented in an aggregated manner through representative line parameters and corresponding line limits as a result of the network reduction methodology.

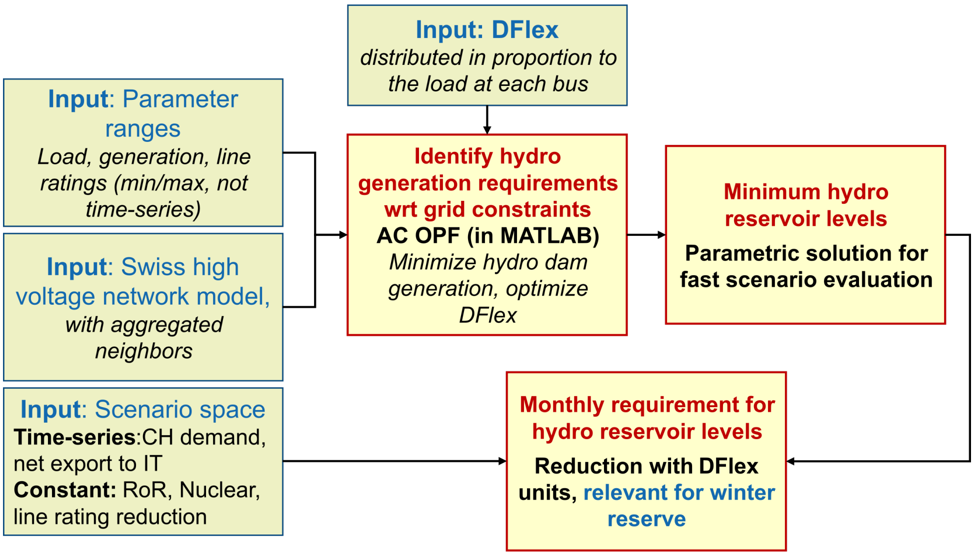


Figure 55: Framework for the assessment of the system benefits by DER flexibilities

The following parameters are fixed (i.e., not optimized) in the model and varied as a sensitivity parameter to assess the impact:

- The production by Swiss nuclear power plants (kept constant either at today's amounts or decommissioned to represent a future scenario).
- Run-of-River (RoR) hydro production (using representative values).
- Transmission line ratings (reduced to 80% of the nominal capacity to take into account N-1 security).

In addition, the repeated solution of the AC OPF model uses the following modeling assumptions:

- Swiss hydro dams operate proportionally up or down according to a fixed generation key (based on their rated power), the distribution of the generation between the power plants is not optimized.
- All generators are assumed to be providing reactive power at the same power factor to ensure AC feasibility.
- Net export to Italy is increased in steps (the first dimension of the scenario space).
- For each Italian import value, Swiss demand is increased in steps (the second dimension of the scenario space).
- The production of the other neighbors (France, Germany and Austria) serves as slack concentrated in one node for each country.

Note that the detailed cost of generation is not taken into account since the methodology seeks to determine the minimum requirement for Swiss local production. Therefore, the cost objective of the AC OPF uses a zero cost for the northern neighbors (using them as much as possible within the network limits), and a positive cost for the hydro dam production within Switzerland (using them only when the import from the northern neighbors is limited). The methodology and the framework employed in this work builds upon and expands the work performed within the context of SCCER-Digitalization [51].

5.1.3 Assessment of hydro reservoir requirements

This section describes how the AC OPF framework is used to assess the impact and benefit of DER-flexibility resources for the operational security of the Swiss transmission grid, relieving production from

Swiss hydro dam generation. The three steps outlined in the overview of section 5.1.1 are applied as follows.

The first step identifies the boundary conditions of the transmission network by performing repeated AC OPF on a 2D scenario space, where each point corresponds to a pair of Swiss demand and net export to Italy. For each amount of net export to IT we increase the Swiss demand and perform an AC OPF. We repeat this 2D-iteration procedure of increasing Italian imports and Swiss loads until the problem reaches an infeasible point. The results of the scenario space allow to interpolate the hydro dam generation results for different values of Swiss demand and export to Italy.

Step two of the methodology uses the hourly time series of total energy consumed by end users in the Swiss control block as described in Section 2.1 (after subtracting the PV time series corresponding to a future scenario) and the hourly time series of the net export from Switzerland to Italy to interpolate the hydro dam generation results for every hour in a year based on the AC OPF results of the initial scenario space.

The resulting hourly hydro dam generation is dependent on the fixed parameters listed in section 5.1.2 (i.e., the generation by RoR and nuclear plants, transmission thermal line ratings) as well as the aggregated flexibility by DERs. To estimate the amount of aggregated flexibility that can be offered on a continuous basis across Switzerland, we use the results of Section 3. We assume that aggregated flexibility is available at each load bus proportional to the nominal load and vary the total flexibility available across Switzerland. This corresponds to a simplification of the time-dependent available flexibility in the representative district grid by scaling the profiles calculated in Section 3 to a value that is guaranteed to be continuously available.

Once we assign each load bus an aggregated flexibility, hereinafter referred to as DFlex unit, we assume that they act as generators and can provide maximum active/reactive power. As an example, if 500 MW / 50 MVAr of aggregated flexibility is available throughout Switzerland on an hourly basis (corresponding to $\sim 1'000$ communities in the distribution grid, aggregated based on the results of Section 3), there is an average of $\sim \pm 4.5$MW and $\sim \pm 0.45$MVAr flexibility at each of the ~ 110 load buses in the high voltage transmission grid. The median flexibility per node is $\sim \pm 3$MW and $\sim \pm 0.3$MVAr. According to the results of section 3, each aggregated flexibility can provide active and reactive power in both directions.

It is noted that, in addition to assessing the reduction in active power generation of hydro dams, we assess the reactive power generation of those units to be able to evaluate the overall benefits. We analyze the voltage profile of the transmission network and measure the "flatness" of the profile (how close the voltages are to 1 p.u.) by using the root-mean-square deviation metric as follows:

$$V_{RMSD} = \sqrt{\frac{\sum_{i=1}^{N_{bus}} (1 - |V_i|)^2}{N_{bus}}} \tag{18}$$

5.2 Quantitative results

This section provides a set of quantitative results to illustrate the methodology and demonstrate the benefits of utilizing aggregated flexibility.

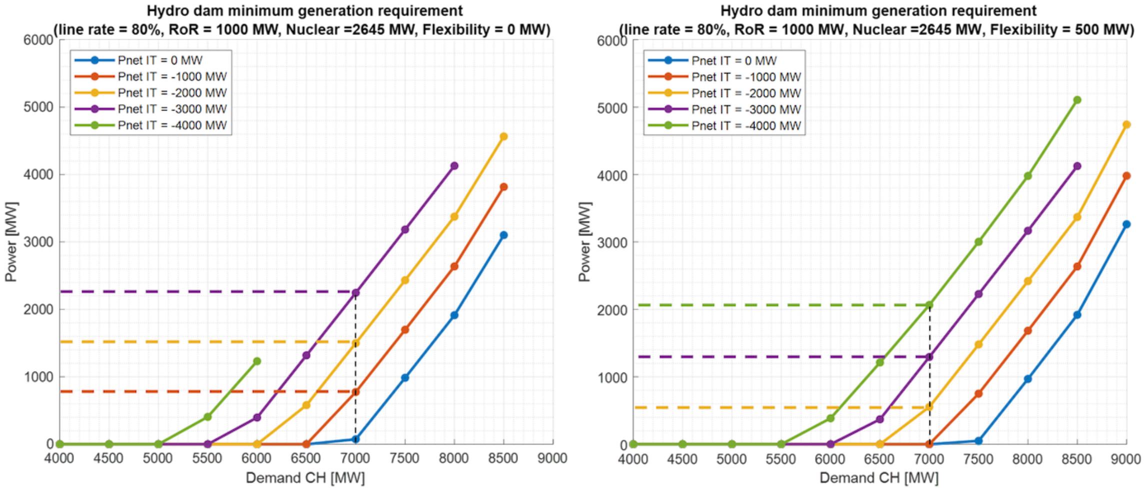
The PV generation time series created for 2050 scenario as described in Section 2.1 are scaled down by half, corresponding to a $\sim$ 20GWp installed capacity, and subtracted from the load time-series. For AC feasibility, all generators in the system are assumed to have reactive capability of a power factor of ± 0.9 (except DFlex units, who have a different power factor). Based on the analysis of the calculated available flexibilities (corresponding to ramping up by increasing local generation, decreasing demand, discharging BESS if it is on hold or charging) in Section 3 for the selected distribution network and the community, it is assumed that a meaningful number of similar communities are contributing to aggregated flexibility at each load bus at the transmission level to reach the total (nationwide) DFlex levels assessed in this study: 50 MW, 100 MW, and 500 MW. We use the demand data time-series for total energy consumed by end users in the Swiss control block as stated in Section 2.1, and for the Swiss-Italian energy flows to calculate the net export to IT. We subtract the PV time-series from the CH demand time series to obtain the "net demand" seen at the transmission level. We do not allow that excess PV production is overflowing to the transmission network, which translates into $\sim$ 1% ($\sim$ 0.18**TWh**) of the produced energy by PV on an annual basis being curtailed. The following parameters are varied to represent different operating scenarios, but are kept constant during the AC OPF assessments of each scenario:

- Swiss nuclear power plants have a production capacity of either 2'645 MW or 0 MW (phase-out scenario)
- Run-of-River (RoR) hydro production is set to 1000 MW or 2'000 MW (typical seasonal variation is between 1'000 MW and 3'000 MW)
- Line ratings are set to as 80% percent of the nominal maximum capacity as an approximation of the requirements to ensure N-1 security.
- The 2D scenario space for Swiss demand and export to Italy is created as follows: Net export to Italy is increased from 0 MW in 1'000 MW steps and for each Italian import value, Swiss demand is gradually increased from 0 MW in 500 MW steps.

For AC OPF calculations MATPOWER [47] in MATLAB environment is used and the optimization structure is modified to accommodate our needs.

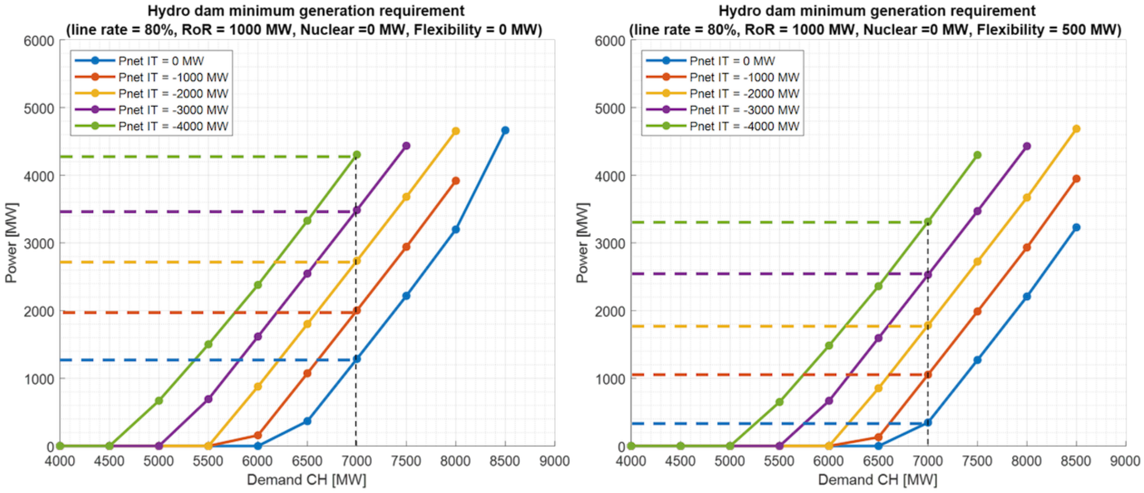
The AC OPF results for selected pairs of Swiss demand and export to IT are demonstrated in Figures 56 and 57, with and without nuclear plants and with and without flexibility. The RoR production is kept constant at 1'000 MW. The results represented in Figures 56 and 57 can be used as a lookup table, as they provide the required hydro production for a given Swiss demand and export to Italy. The benefits of utilizing DFlex units, are two-fold, and can be observed along both axes:

1. Additional flexibility in the system increases the level of CH loading when hydro power generation starts to be required. For example, the need for hydro generation can be observed when the Swiss demand reaches 5'500 MW combined with an export of 3'000 MW to Italy; while the Swiss demand can be supplied without the need for hydro generation until $\sim$ 6′000MW, for the same export amount to IT, thanks to 500 MW / 50 MVAr flexibility.
2. Thanks to the additional flexibility in the system, spread throughout the country, for a given export value to IT, the drop in required active power generation from hydro dams can be easily observed (dashed horizontal lines in the Figures). For example, to meet a Swiss demand of 7'000 MW and export 3'000 MW to Italy with nuclear production, DFlex of 500 MW / 50 MVAr reduces the required hydro production from 2'200 MW to 1'200 MW. Note that the reduction is almost double the amount of flexibility (500 MW). However, it is noted that, for this operating point, the hydro generators increase the reactive power generation compared to the case when there is no flexibility, and if the


Hydro dam minimum generation requirement (line rate = 80%, RoR = 1000 MW, Nuclear =2645 MW, Flexibility = 0 MW)

Hydro dam minimum generation requirement (line rate = 80%, RoR = 1000 MW, Nuclear =2645 MW, Flexibility = 500 MW)

Figure 56: Required hydro dam power generation determined using AC OPF for scenario sample space of CH demand (horizontal axis) and CH2IT export pairs (different colours). [The nuclear power plants are in operation in both cases.] **Left**: without flexibility, **Right**: with 500 MW flexibility


Hydro dam minimum generation requirement (line rate = 80%, RoR = 1000 MW, Nuclear =0 MW, Flexibility = 0 MW)

Hydro dam minimum generation requirement (line rate = 80%, RoR = 1000 MW, Nuclear =0 MW, Flexibility = 500 MW)

Figure 57: Required hydro dam power generation determined using AC OPF for scenario sample space of CH demand (horizontal axis) and CH2IT export pairs (different colours).[The nuclear power plants are phased out in both cases.] **Left**: without flexibility, **Right**: with 500 MW flexibility

apparent power is taken as the measure, the benefit is still high but not double.

It has been observed that an increased amount of reactive power support further increases the benefit. When nuclear power production is reduced to zero in Figure 57, and the RoR production is kept constant, the overall hydro production requirement increases, but the relative benefit of of DFlex support is maintained.

Once the OPF results of the initial scenario space is obtained, we apply our parametric interpolation method to calculate the hydro power generation for a full year in a hourly resolution. The results are presented in Figures 58 and 59 for the case when the nuclear plants are still in service. Note that the blue curve represents the net demand as mentioned above (PV subtracted from the demand).

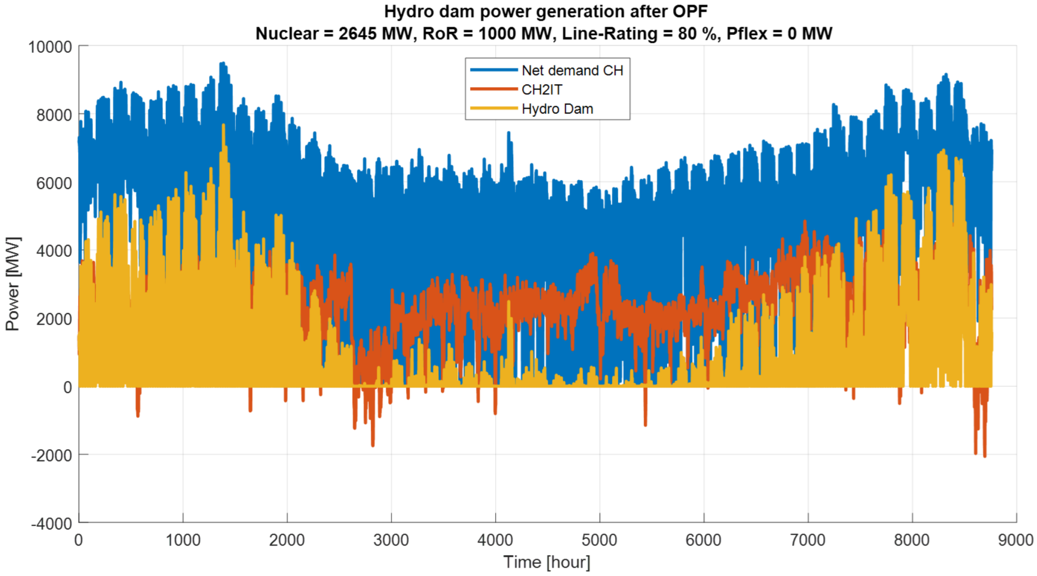


Figure 58: Hydro dam power generation, results of OPF and interpolation process, PV production subtracted from the Swiss demand, no flexibility available [The nuclear power plants are in operation.]

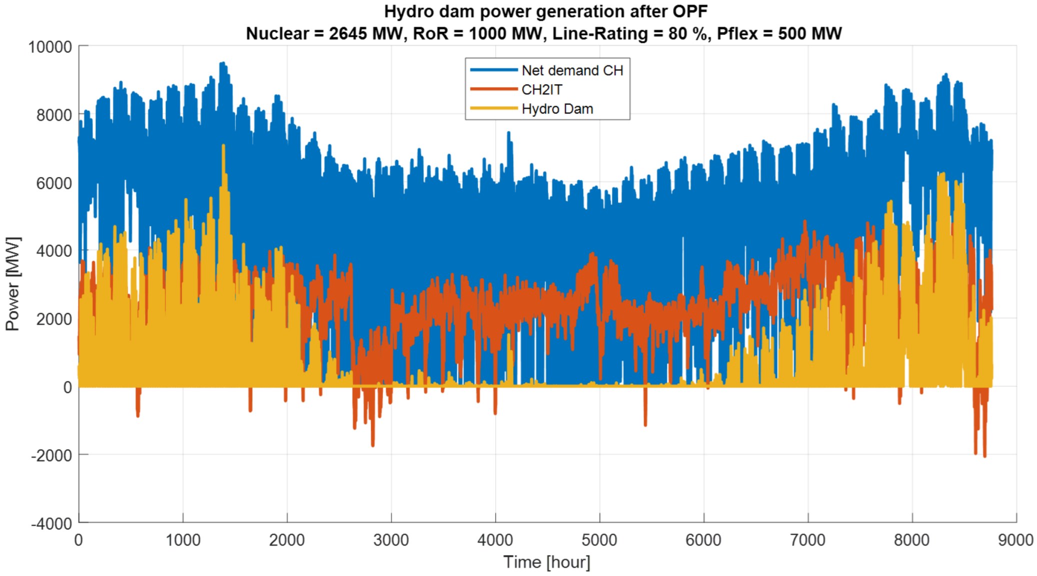


Figure 59: Hydro dam power generation, results of OPF and interpolation process, PV production subtracted from the Swiss demand, DFlex: 500 MW [The nuclear power plants are in operation.]

The benefit of using the DFlex can be observed by focusing on the yellow curve and the decrease in hydro production is evident at all times of the year. The reduction can more clearly be observed in Figures 60 and 61 for the case without nuclear production, especially in the summer season.

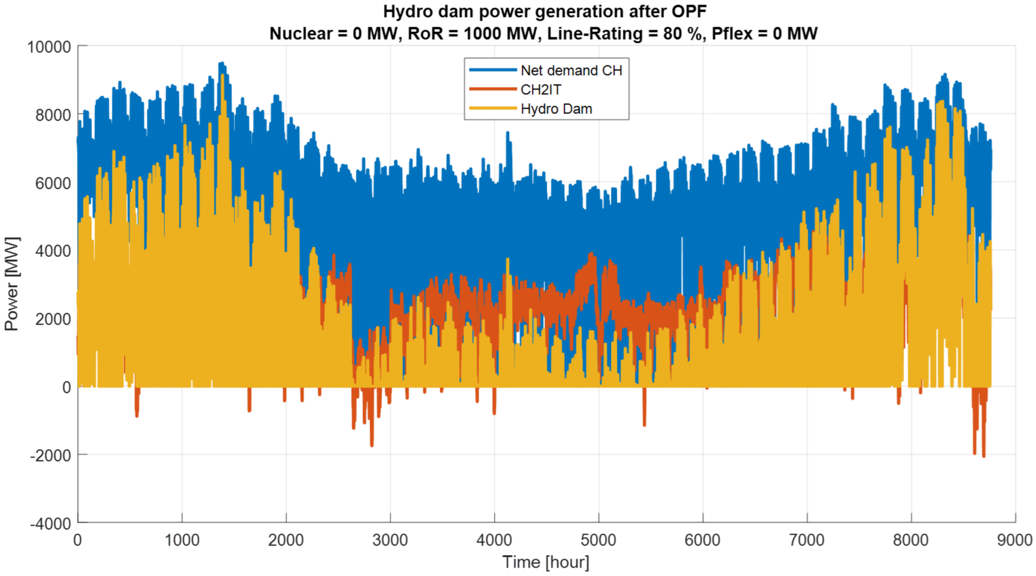


Figure 60: Hydro dam power generation, results of OPF and interpolation process, PV production subtracted from the Swiss demand, no flexibility available [The nuclear power plants are phased-out.]

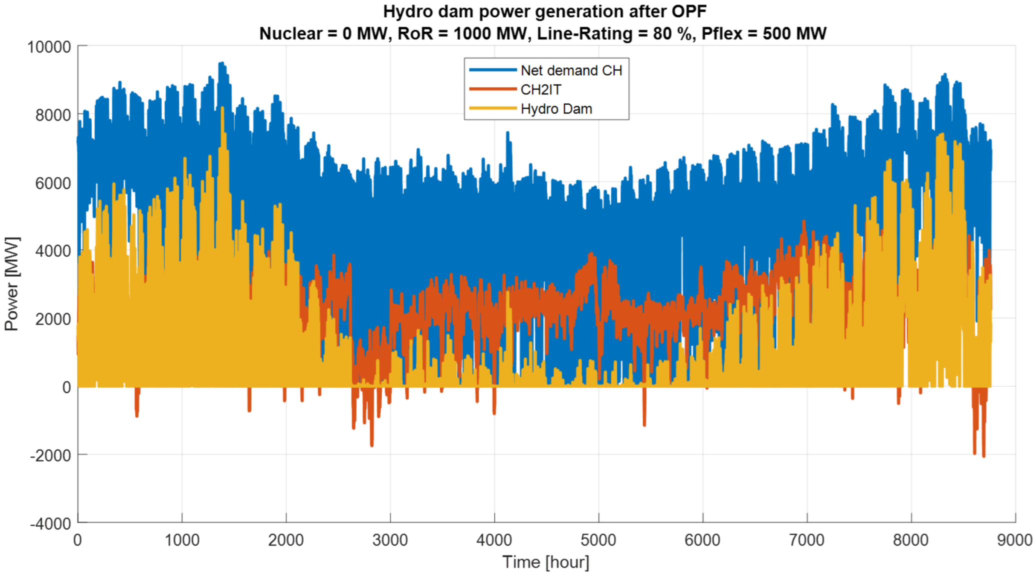


Figure 61: Hydro dam power generation, results of OPF and interpolation process, PV production subtracted from the Swiss demand, DFlex: 500 MW [The nuclear power plants are phased-out.]

To be able to demonstrate the seasonal variation in minimum hydro generation requirements as well as the impacts of different aggregated flexibility amounts we present the Figure 62, with the nuclear plants in service and the Figure 63, with the nuclear plants decommissioned. In these figures the hydro power is integrated over the month to demonstrate the corresponding hydro energy that must be reserved in the storage dam. The result is a monthly energy requirement, which reduces as the available aggregated flexibility increases from 10 MW / 1 MVAr to 500 MW / 50 MVAr distributed throughout the network. In presences of nuclear, the benefit of the flexibility is insignificant in summer season. However, it can be observed in Figure 63 that, in addition to the obvious reduction in the winter months thanks to the aggregated flexibilities, there is also benefit by DFlex units in summer season. Note that this benefit can increase significantly if the import capabilities from the neighbors (DE, FR, and AT) are further reduced, for example, to half of the current NTC levels.

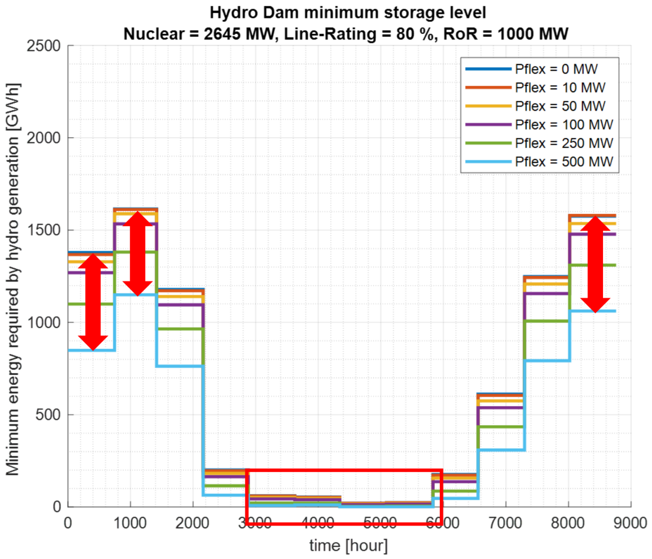


Figure 62: Total required energy by hydro dams, with nuclear, with respect to different DFlex availabilities

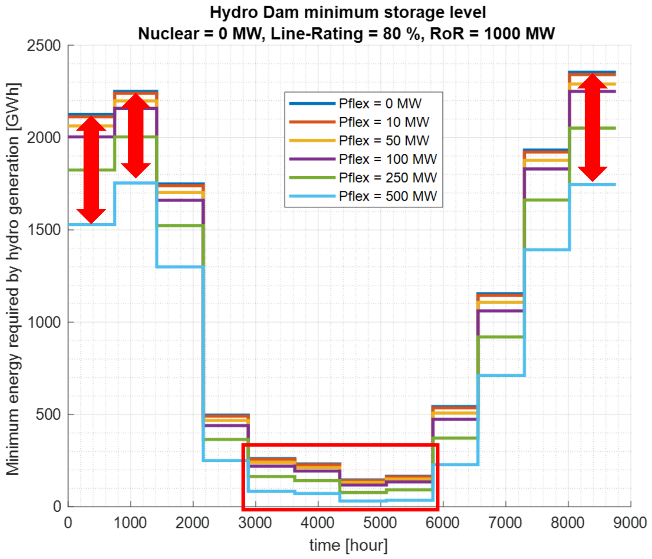


Figure 63: Total required energy by hydro dams, without nuclear, with respect to different DFlex availabilities

Figures 64 and 65 summarize the benefits in terms of the reduction in hydro energy requirements with respect to varying amount of DFlex units. While the main benefit always occurs in the winter months, note the increased benefit during summer months when the nuclear plants are decommissioned.

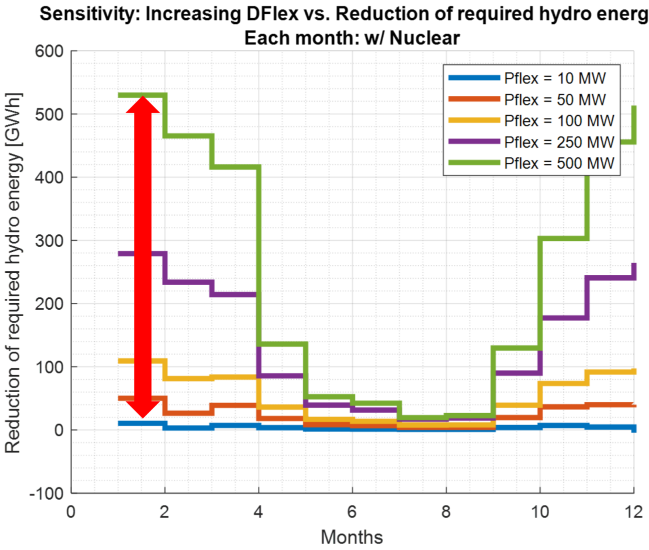


Figure 64: Reduction of required hydro energy, with nuclear plants, with respect to different DFlex availabilities

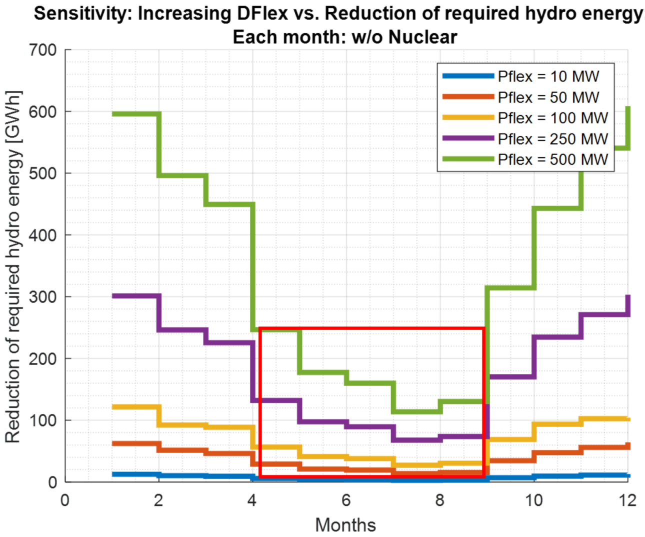


Figure 65: Reduction of required hydro energy, without nuclear plants, with respect to different DFlex availabilities

The impact of nuclear plants being in service or being decommissioned on the DFlex capability to reduce the required hydro energy production is demonstrated in Figures 66,67, and 68 for a total aggregated flexibility of 50 MW, 100 MW and 500 MW, respectively. It is important to note that nuclear plants are concentrated on one part of the transmission network, while the flexibility aggregation is performed at every load bus. The flexibility units enable a better distribution of loading of lines throughout the network, in particular when production is concentrated at nuclear power plants. This is confirmed by figures 69 and 70, showing the impact of DFlex units on the reduction of loading in transmission lines, in presence of and absence of nuclear plants. It has also been observed, that the flexibility units contribute to more balanced voltage profile by providing reactive power support.

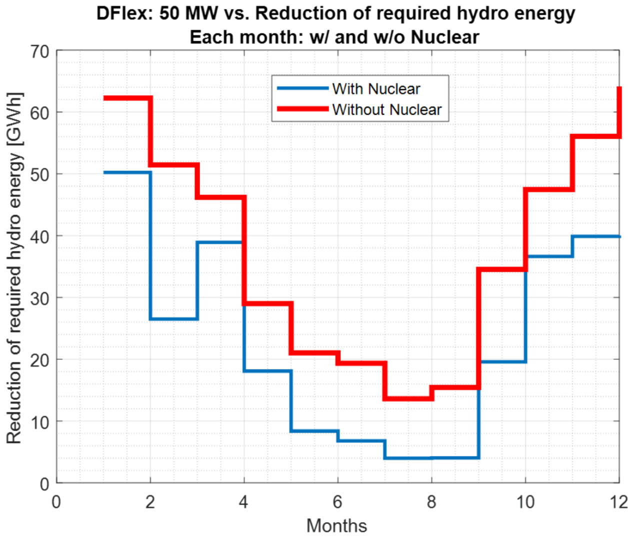


Figure 66: Reduction of required hydro generation by DFlex: 50 MW: with and without nuclear plants

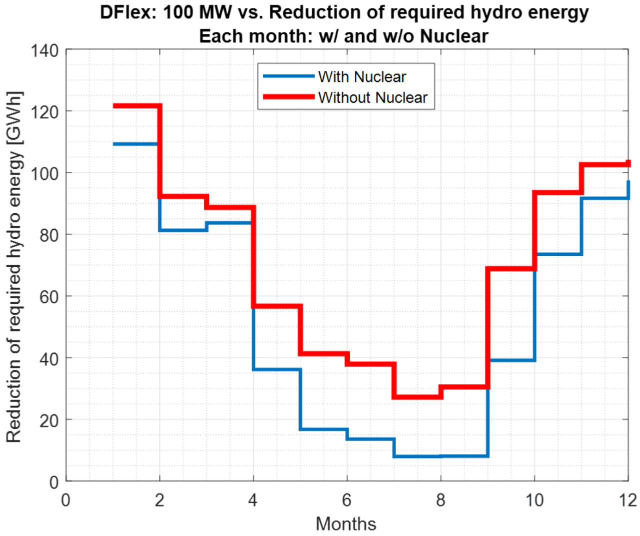


Figure 67: Reduction of required hydro generation by DFlex: 100 MW: with and without nuclear plants

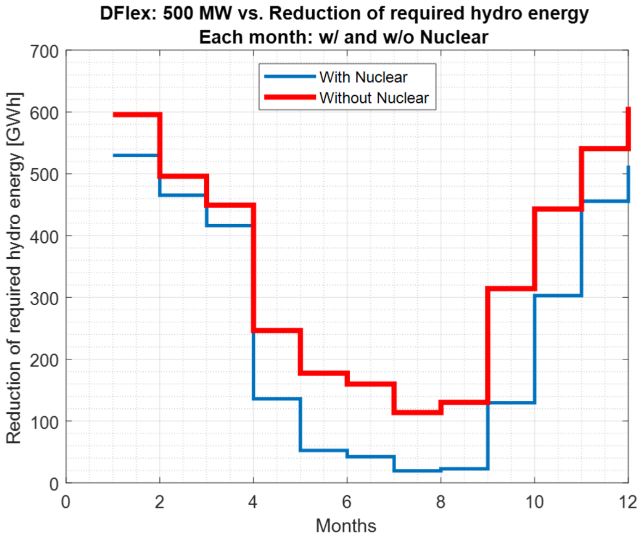


Figure 68: Reduction of required hydro generation by DFlex: 500 MW: with and without nuclear plants

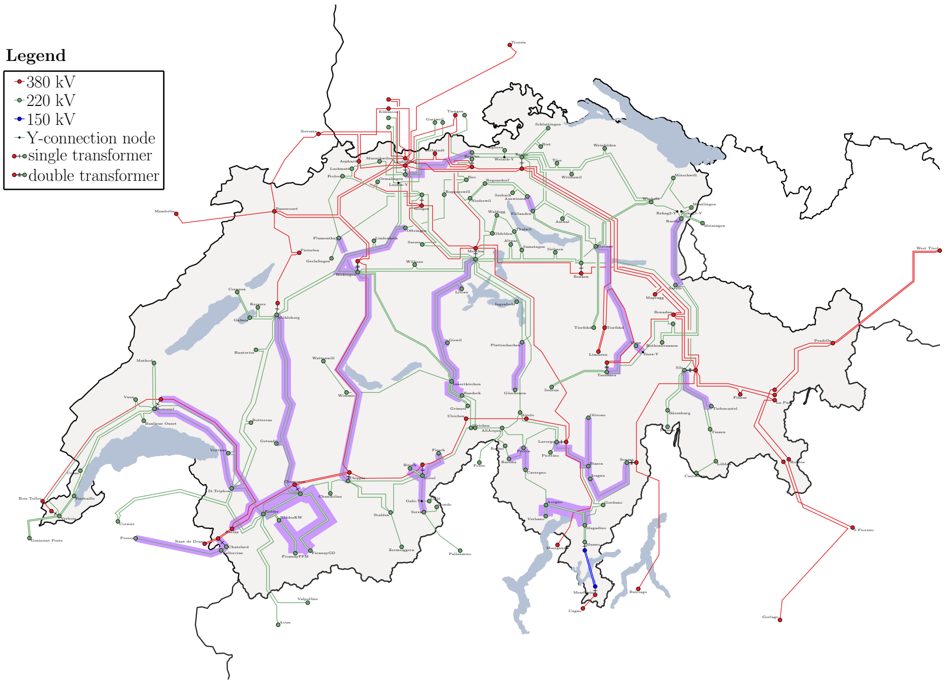


Figure 69: Transmission lines with more than 5% of loading reduction highlighted in purple due to 500MW / 50 MVAr flexibility in the system [The nuclear power plants are in operation.]

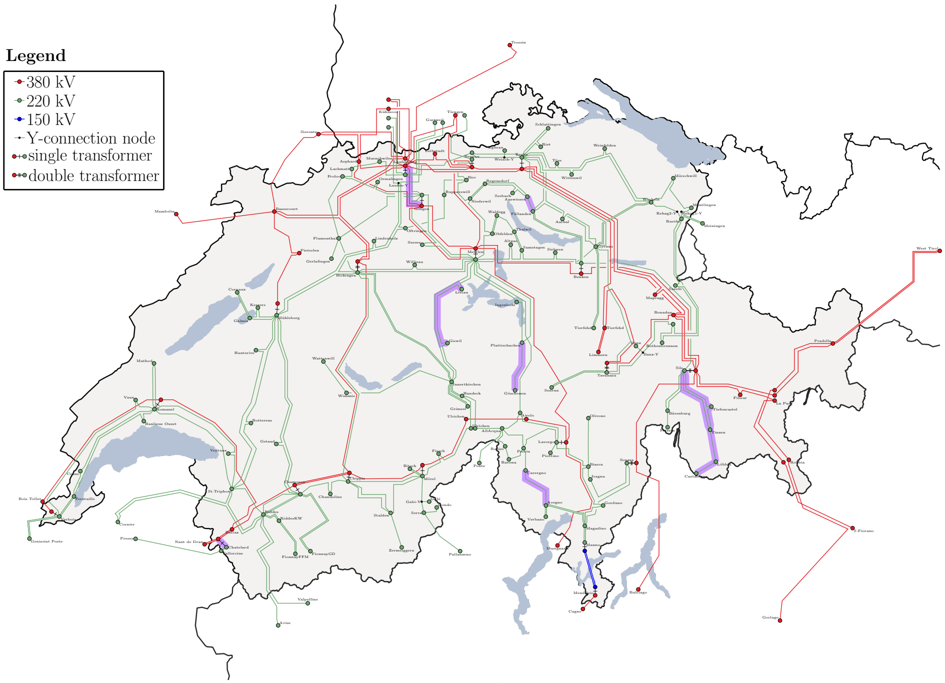


Figure 70: Transmission lines with more than 5% of loading reduction highlighted in purple due to 500MW / 50 MVAr flexibility in the system [The nuclear power plants are phased-out.]

It is important to observe how the aggregated flexibility at each load bus behaves for the sampled scenario space which is described in the methodology. There are 93 sampled operating points corresponding to the initial 2D scenario space. Figures 71 and 72 show the participation of each DFlex by providing active power flexibility, while the Figures 73 and 74 show the DFlex units providing reactive power flexibility, both in presence of nuclear plants as well as when nuclear plants are decommissioned. For each DFlex unit, the boxplot contains 93 values, while the black lines denote the maximum and minimum available active and reactive power flexibility at that the corresponding load bus.

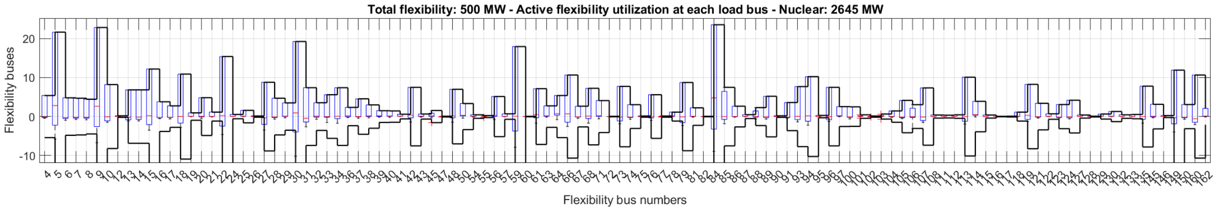


Figure 71: Active power flexibility utilization at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility of 500 MW [The nuclear power plants are in operation]. Boxplots contain 93 values, **Black** lines denote the maximum and minimum available flexibility.

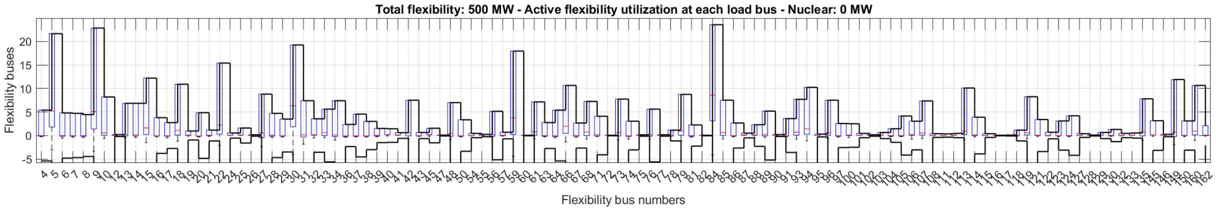


Figure 72: Active power flexibility utilization at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility of 500 MW [The nuclear power plants are decommissioned]. Boxplots contain 93 values, **Black** lines denote the maximum and minimum available flexibility.

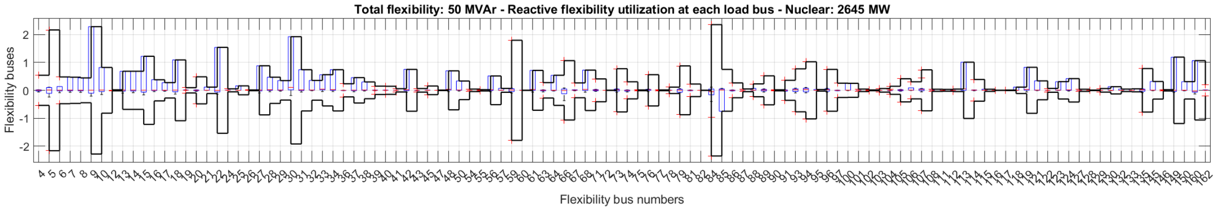


Figure 73: Active power flexibility utilization at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [The nuclear power plants are in operation]. Boxplots contain 93 values, **Black** lines denote the maximum and minimum available flexibility.

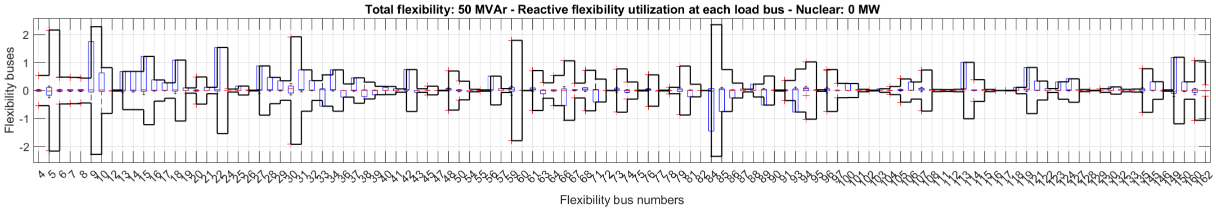


Figure 74: Active power flexibility utilization at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [The nuclear power plants are decommissioned]. Boxplots contain 93 values, **Black** lines denote the maximum and minimum available flexibility.

One important observation is that in presence of nuclear, active power flexibility is used to ”consume” power (corresponding to negative values) as well, even though this is not observed very often. The ”consumption” behaviour by the aggregated flexibility can be obtained by increasing demand (turning on HPs, charging EVs and BESS) and by curtailing solar PV or other local generation as explained in Sections 2.2 and 3. Such need for ”active power consumption” by DFlex units is not observed in the case when The nuclear power plants are assumed to be decommissioned. Another observation is that the available positive active power flexibility is used almost at each node in both cases of nuclear presence and nuclear phase-out.

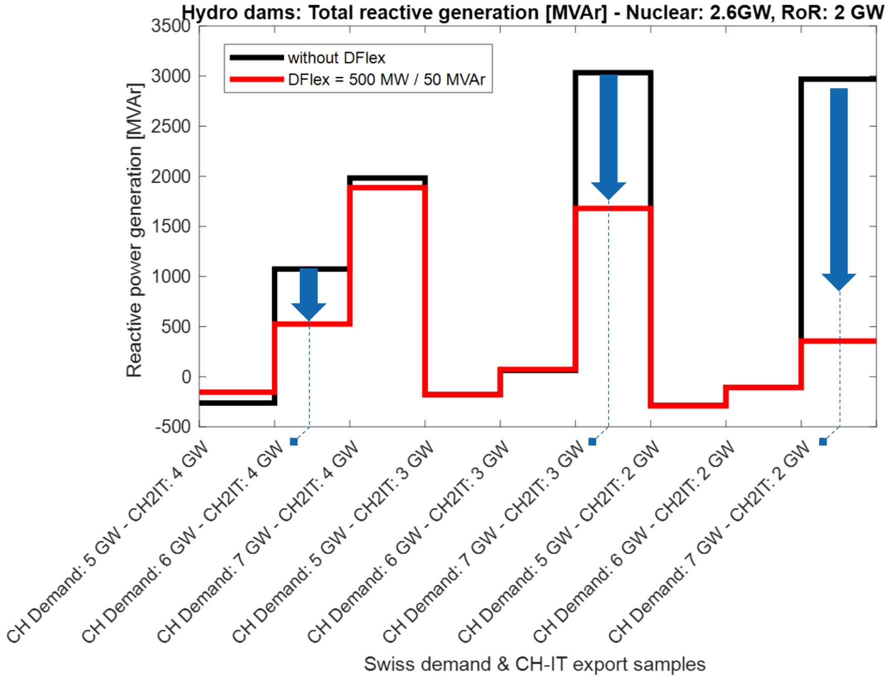


Figure 75: Total reactive power generation by hydro dams for selected combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [in operation]

In the meantime, the reactive power flexibility provided by DFlex exhibits a different behaviour. While the majority of the DFlex units injects reactive power (positive) to the grid in presence of nuclear plants, some flexibility nodes consume reactive power to decrease the nodal voltages and balance the reactive power injected to the system, when nuclear is phased-out and due to the increased import from north. Figures 75 and 76 demonstrate the impact of the reactive power flexibility on the reactive power generation by hydro dams for a smaller set of scenario samples for Swiss demand and export to Italy combinations and with and without nuclear, respectively. In Figure 75, the reduction in total reactive generation by hydro dam power plants is observable for high Swiss demand cases, while in Figure 76, it can be observed that the required reactive power support by hydro power plants slightly increase in high Swiss demand and high export scenarios. Note that the active generation by RoR units are fixed at 2 GW in this illustration.

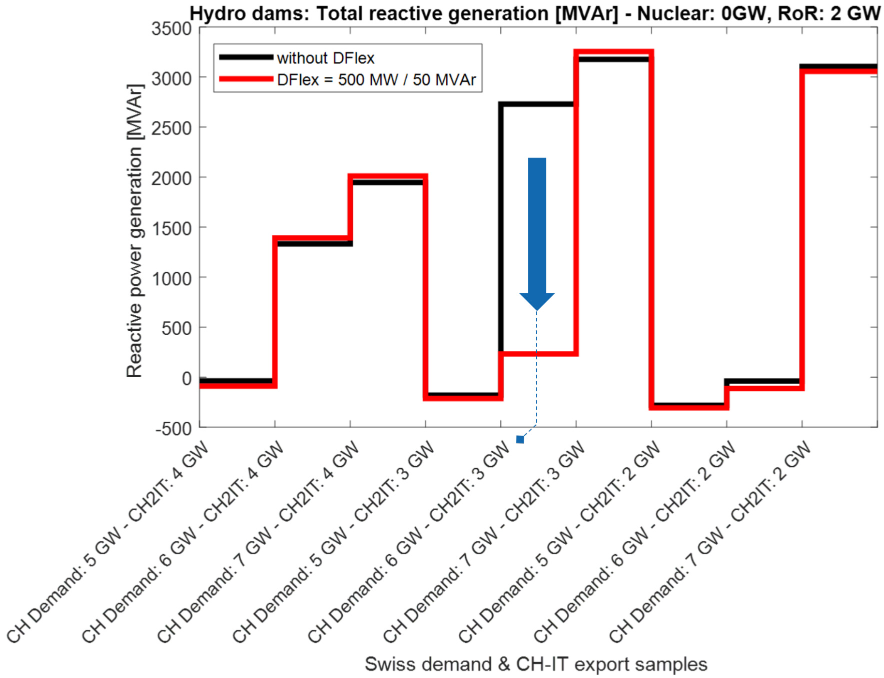


Figure 76: Total reactive power generation by hydro dams for selected combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [The nuclear power plants phased-out]

Finally, Figures 77 and 78 show the variation in the voltages at load buses, where flexibility is available, in presence of nuclear and when nuclear is phased-out, respectively. The metric we used to assess the results is root-mean-square deviation, RMSD (with respect to 1 p.u.), as described in the methodology section.

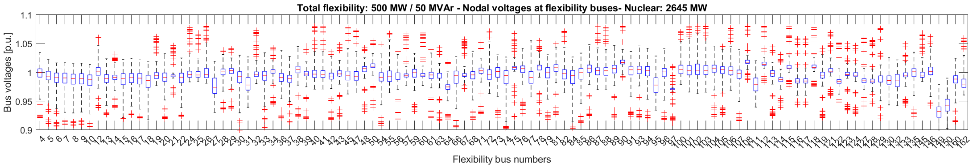


Figure 77: Variation of bus voltages at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility: 50 MVAr. Boxplots contain 93 values, **Red** dots denote the outliers. [The nuclear power plants in operation]

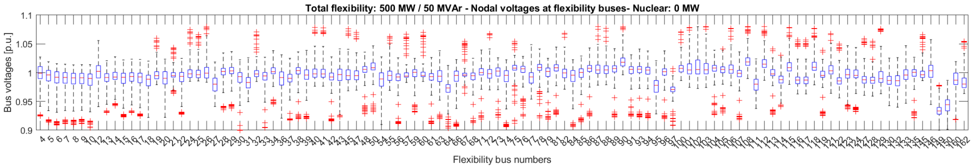


Figure 78: Variation of bus voltages at each load bus for combinations of Swiss demand and export to Italy for a total available flexibility: 50 MVAr. Boxplots contain 93 values, **Red** dots denote the outliers. [The nuclear power plants phased-out]

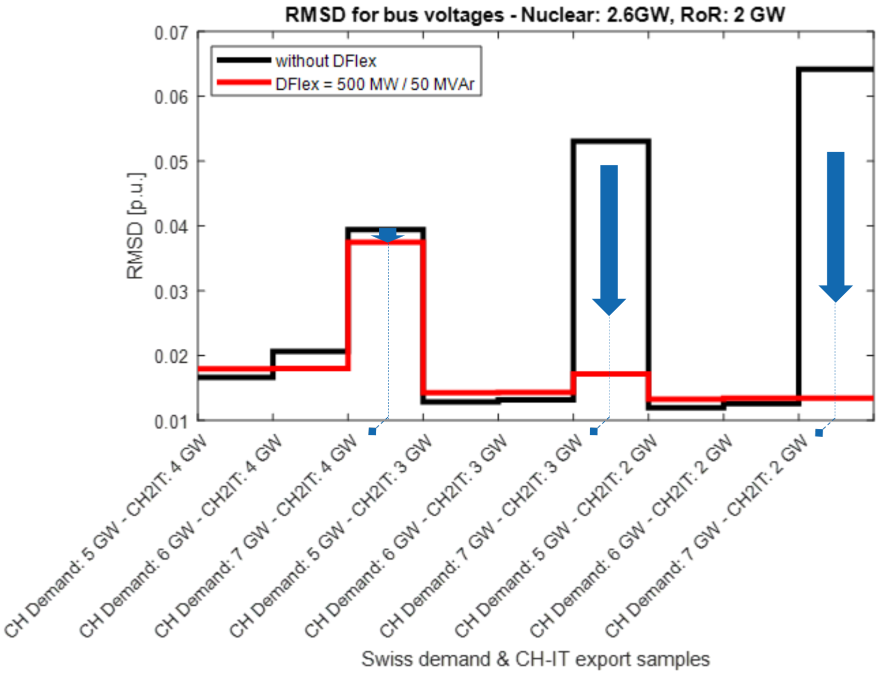


Figure 79: RMSD of bus voltages for selected combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [The nuclear power plants in operation]

The Figures 79 and 80 show the RMSD for a smaller set of scenario samples. Note that, the benefit of the utilization of aggregated flexibility in presence of nuclear plants is highest during moderately high Swiss demand ($\sim 7GW$), and especially when the export to Italy is in moderate levels ($2GW \& 3GW$). As the export to Italy increases, the benefit decreases. Overall, the benefit of the reactive power flexibility by DFlex units can be observed to be higher in presence of nuclear, compared to the case when nuclear

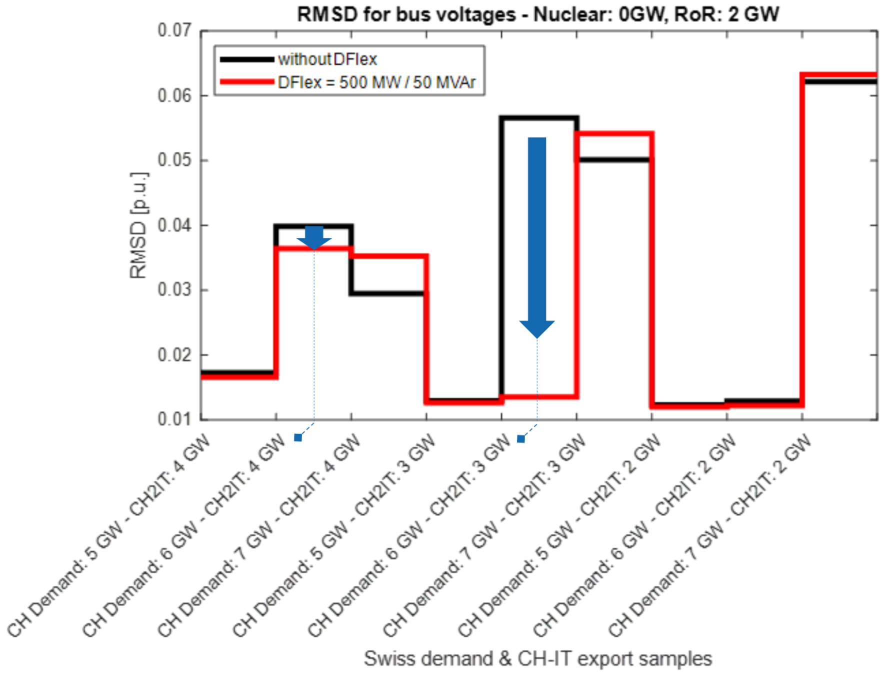


Figure 80: RMSD of bus voltages for selected combinations of Swiss demand and export to Italy for a total available flexibility: 500MW/50 MVAr [The nuclear power plants phased-out]

plants are phased-out. The results show how the reactive power support tends to contribute to a more balanced voltage profile (lower RMSD values). Note that the primary objective of the AC OPF formulation is the maximization of import capacity (or equivalently minimizing the Swiss hydro utilization) while respecting the voltage bounds. As long as the voltage bounds are respected, high or low RMSD values are indifferent from the point of view of the optimizer.

5.3 Discussion

The aggregated flexibilities of DERs (conventional load, HPs, EVs, PV, and BESS) at the TSO-DSO substations have the potential to provide services to the system operation by offering their flexible active and reactive power capabilities in both directions (i.e., as ”generators” and as ”demand ”in Switzerland. An AC OPF problem is formulated such that hydro dam generation is minimized on an hourly basis, while the import from France, Germany and Austria is maximized in presence of the flexibilities distributed throughout the Swiss transmission network at each load bus. To investigate the utilization impact of DFlex units, a number of scenarios with different amounts of aggregated flexibilities are investigated along with the presence and absence of nuclear power plants.

It is important to note that the economic attractiveness of the DFlex units is dependent on (i) wholesale energy prices and (ii) remuneration schemes for DER flexibilities, which constitutes the cost of DFlex units (i.e., minimum price to be paid to the DER owner). Inspecting the unit costs of providing active and reactive power flexibility (”-” flexibility offered by the DFlex units in Figure 12 in Section 2.3), a boundary on economic competitiveness can be identified. It can be concluded that BESS-based DFlex units are competitive when the wholesale energy prices are higher than 150 CHF/MWh and other technologies such as conventional demand, HPs and EVs are competitive when the wholesale energy prices are higher than 50 CHF/MWh.

These conclusions are highly dependent on the selected remuneration system, and the evolution of the retail electricity tariffs. Lower generation requirements of hydro dam plants is a benefit to the overall system and can have the potential to unlock other mechanisms to further compensate the utilization of the DFlex units. It is important to emphasize that the remuneration method does not take into account the impact of providing flexibility services on the technology lifetime, which can further increase the cost of the flexibility by DERs for the system services. It is noted that the lifetime impact will be significantly higher if services are offered in operation, compared to services in reserves, which has low deployment probability.

The benefits of the power flexibility provided by the DFlex units to the system are easily measurable and observable, by observing the reduction in the power generation of the hydro dams as well as loading relief along Swiss transmission lines. The resulting benefits are due to the combined effect of simultaneous provision of active and reactive power flexibility supplied by the DFlex units to the system. It is observed that almost all DFlex units act like generators (providing ”-” flexibility, by decreasing demand or discharging BESS) and inject active power into the system, while there are few instances that they provide ”+” active and reactive power flexibility by acting like demand (+ flexibility, by increasing demand, charging BESS, curtailing solar).

The contribution of BESSs is the main driving factor and availability of aggregated BESS is essential to ensure that a meaningful amount of power flexibility is offered. The total available reactive power flexibility is, however, restricted due to the limitations of BESS in injecting reactive power to the system. It is noted that the resulting benefit by DFlex units can be reduced significantly due to low proliferation of BESS by solar PV owners. In that case, the aggregator shall resort to higher number of communities, with other DERs such as conventional demand, HPs, and EVs available to provide flexibility.

The aggregators can resort to methods to utilize active power flexibility only in selected load buses and reactive power flexibility in other buses, to maximize the flexibility extracted from the DFlex units. The selection process can be based on the needs of the transmission system operator and provision of such dedicated services may be remunerated differently.

Given the time-, availability- and forecast-dependent nature of the flexibilities, it is important to note: (i) simultaneously aggregating the DER flexibilities offered by multiple communities is assumed to be performed by an aggregator by employing intelligent ways of procuring the flexibility so that same DERs are not relied upon all the time, (ii) in Section 3 it is assumed that BESS is discharged during the night and does not start charging until there is excess solar. Since the probability of excess solar occurrence is very low especially in winter times, BESS will be idle under this assumption. However, the DER owner may be motivated via a remuneration scheme during these idle times, so that BESS units can still be utilized for operational flexibility.

6 Conclusions

To assess the benefits of utilizing flexibilities that can be potentially offered by DERs such as small-scale solar PV, residential BESS, residential electric heat pumps and personal EVs in medium- or low-voltage distribution grids, we developed a framework from two perspectives: bottom-up and top-down.

The **bottom-up** perspective involves three aspects. First, we create scenarios and utilization patterns (i.e., time-series of conventional demand, HPs, EV charging, solar PV generation, BESS charging/discharging) for a representative LV grid in 15-minute resolution on representative days, and identify the availability boundaries of each DER. Secondly, we calculate the maximum feasible flexibility that can be offered by each DER, aggregated at the trafo station using AC optimal power flow and maximize the ”additional” positive/negative active and reactive power exchange at the trafo station around the operating point, while respecting the distribution grid thermal loading and voltage constraints. The result is a time-series of maximum ”additional” flexibility in each direction for active and reactive power, constituting a ”flexibility region” around an operating point at the trafo station. Lastly, we identify a remuneration scheme for each DER, so that the identified ”flexibility region” is associated with a cost.

The **top-down** perspective refers to assessing the benefits of utilizing the aggregated flexibilities provided by a large number of distribution grids throughout Switzerland in two case studies. First, for frequency reserves, we formulate a co-optimization problem for the simultaneous dispatch of energy and reserves. The problem includes the neighboring countries and is solved at the country level. Secondly, in daily operation, we study how aggregated flexibilities can relieve the required power generation by hydro dams so that the hydro plants are less constrained during the winter months. The problem is formulated as an hourly AC optimal dispatch considering the full Swiss transmission network while each neighbor is aggregated to one node. Following are our take-away messages of our investigations:

Benefits for reserve: The aggregated flexibilities of the components that make up the represented DFlex unit (conventional load, HPs, EVs, PV, and BESS) have the potential to provide services to the electricity market through offering their flexible active power capability (positive and negative) as a capacity reserve in Switzerland. Following, we summarize our observations:

- The downward reserves (i.e., ramping down flexibility) provided by BESS, conventional demand, HPs, and EVs have the greatest potential for reserve procurements because these DERs together have significant available power during hours when their offer price is below the reserve price.
- The impact of procuring aggregated DER flexibilities for reserves is consistent across all simulated scenarios. The use of DERs for upward reserves relieves hydro capacities, which in turn produce more energy in place of other more expensive generators, leading to lower total dispatch costs.
- The remuneration scheme is a critical assumption in this assessment since it has the most direct influence on when DER flexibilities are cost competitive.
- Most offer prices by aggregated DER flexibilities (both high and low) are in close range of the reserve prices and different remuneration schemes would likely fall into this same range, where the capacities of DER flexibilities are shown to be competitive and provide useful system benefits.
- While the Swiss and wider European system dispatch is clearly sensitive to restrictions on the market NTCs, the price of natural gas, and the level of RES integration achieved, all three system aspects have little effect on the use and benefits of aggregated DER flexibilities for reserves. Overall, the influence of the remuneration scheme is more significant than the changes in the system-wide conditions.
- Utilization of DER flexibilities leads to proportional decreases in the system dispatch cost. This means that there is potential for additional remuneration of the aggregated flexibility resulting from system costs savings, in addition to the remuneration the DER owners already receive to compensate for their loss of opportunity.

Benefits for operation: The aggregated flexibilities of DERs (conventional load, HPs, EVs, PV, and BESS) at the TSO-DSO substations have the potential to provide services to the system operation by offering their flexible active and reactive power capabilities (in both directions) as ”generators” in Switzerland.

- Utilization of DER flexibility can potentially help reducing required hydro dam generation requirements (relevant for “winter reserves”).
- The aggregated DER flexibility at all load buses throughout the Swiss transmission grid can potentially alleviate internal CH transmission grid loading and support the voltage profile, resulting in more efficient network utilization. This benefit reduces if the DER flexibility is concentrated to selected load buses.
- The benefits of DER flexibility in reducing the required hydro dam generation requirements increase especially following the phase-out of nuclear units.
- Reactive power provision by solar PV and residential BESSs are at the expense of reducing the active power utilization. Therefore the remuneration of reactive power provision is high and not competitive with the current reactive power pricing structure of Swissgrid. However, if the overall system benefit is taken into account (increase of cheap import of active power with the help of adjustments of the reactive power thanks to the flexibilities), these services can be subsidized, thus enabling them to provide services.
- The benefit of flexibilities is greatest during times of high loading of the transmission system (through transit flows or high demand). If the flexibilities, spread throughout the network, assembled by the aggregators can not be provided at the same level in a continuous manner (as assumed in Section 5), further investigations are required to identify the critical times for flexibility requirements by the system operators. For example, the availability of different flexibility types vary over time (e.g., demand cannot be decreasing its demand at every hour, while a residential BESS can only discharge until it is empty), that may not coincide with the time of greatest benefit to system operation.

Flexibilities and aggregation process

- To accurately capture the behaviour and the potential of the available flexibility that can be provided by small DERs so that they can be aggregated to provide services, it is essential that DER consumption/generation/charging are measured in sub-hourly time resolution (e.g., 5- or 15- minute). This is true for the ”availability signal” concept we proposed as well, which helps the DER owners to communicate the availability status of their assets in high time resolution.
- *Impact of remuneration on competitiveness*: Aggregated DER flexibilities are competitive for reserve and operation services under the following conditions:
  - during low-tariff hours, especially if the electricity tariff is in the range of or lower than the wholesale energy prices or reserve prices in Switzerland because the main contributors to the flexibility provision are BESSs and the remuneration of BESS owners, based on the loss of opportunity, is driven by the consumer’s low tariff.
  - when the wholesale price is high (impacting the service offered to reserve up and daily operation) [large difference between 2020 vs. 2050].
  - when the difference between the consumer’s high-tariff and low-tariff is small.
  - when solar remuneration is low, especially lower than the wholesale energy prices or reserve price in Switzerland.

7 Suggestions for future research

- It is challenging but essential to intelligently aggregate multiple communities with DERs such that the same resources are not utilized too often, resulting in the reduction of the lifetime of the DER technology. The ”availability signal” concept proposed in this study is a practical solution to this phenomenon, however, further research is required to assess alternative methods.
- Other means of increasing DER profitability should be investigated. One option is by distributing, at least a portion of the system benefit thanks to the utilization of flexibility, to the DER owners, in addition to remuneration assumptions made in this study based on the owner’s opportunity cost.
- Integrating the bidding strategies and the market behaviour of the generators to the overall benefit assessment should be further investigated.
- The rule-based remuneration scheme assumed in this study for the DER owners may overestimate the amount of the required payment for the services offered by the DER to the TSO. Other schemes, including local dynamic retail prices should be investigated.
- The higher time-resolution (daily instead of weekly, sub-hourly instead of hourly) of reserve markets are expected to enable extracting more benefits from the DERs, which should be further investigated.
- The process of calculating the aggregated flexibility at the TSO-DSO substation can be expedited by using a combination of the adopted optimization process and a Monte-Carlo simulation based on selective sampling of the DER setpoints to identify the outer edges of the boundary. In addition, the parallelisation of the process can be further investigated since calculation of the aggregated flexibility at each time step is independent of each other, and can be performed in parallel.
- Feasibility and liquidity of potential flexibility markets needs further research. The flexibility market can be combined with a ”scheduling” framework, resulting in a complex mixed-integer non-linear programming problem handling large numbers of small DERs. The implementation requirements of such a framework needs attention and further investigation.
- The aggregators can resort to methods to utilize active power flexibility only in selected load buses and reactive power flexibility in other buses, to maximize the flexibility extracted from the DFlex units. The selection process can be based on the needs of the transmission system operator, using an optimization process or a sensitivity-based methodology (especially for voltage support, since it is a ”local” problem). Further research is required to assess the increased benefits by separating the utilization of aggregated active and reactive power flexibilities. Provision of such dedicated services may be remunerated differently due to the priority and urgency of the need of the system operator.
- We implemented a DC approach to emulate the reserve markets through a co-simulation (energy and reserve) formulation. As a next step the AC formulation for the energy dispatch can be integrated to better assess the simultaneous offering of services in reserves and energy dispatch. As part of such a step, the model input would also need to be extended to capture the full Swiss network as well as the nodal breakdown of demand and supply and the two week simulation period would be broadened to cover all hours of the year.
- For the operational assessments in Section 5, further investigations are required to identify the critical times for flexibility deployment. This is particularly important if the flexibilities from the aggregators can not be provided in a continuous manner.

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