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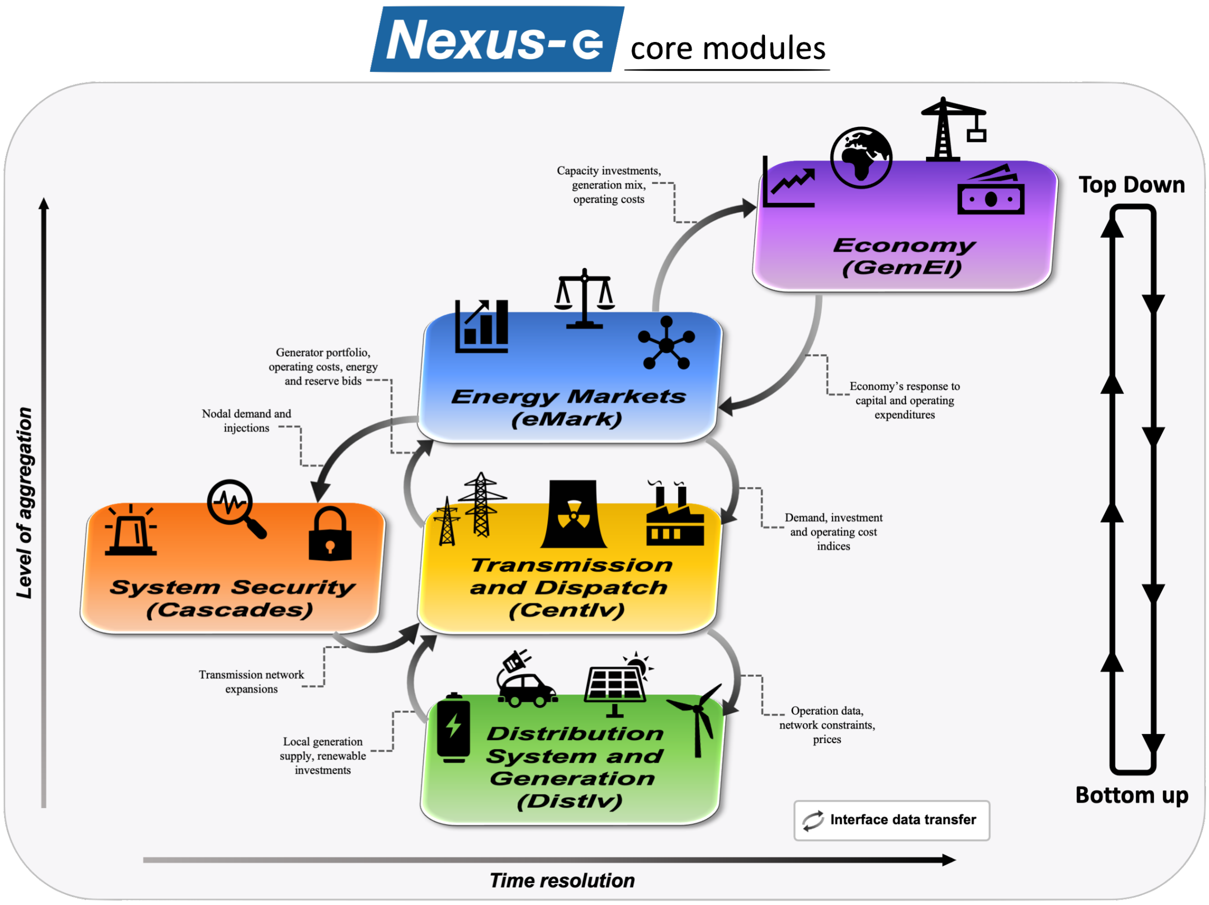
Final report

Nexus-e: Integrated Energy Systems Modeling Platform

Distlv Module Documentation



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Summary

Policy changes in the energy sector result in wide-ranging implications throughout the entire energy system and influence all sectors of the economy. Due partly to the high complexity of combining separate models, few attempts have been undertaken to model the interactions between the components of the energy-economic system. The Nexus-e Integrated Energy Systems Modeling Platform aims to fill this gap by providing an interdisciplinary framework of modules that are linked through well-defined interfaces to holistically analyze and understand the impacts of future developments in the energy system. This platform combines bottom-up and top-down energy modeling approaches to represent a much broader scope of the energy-economic system than traditional stand-alone modeling approaches.

In Phase 1 of this project, the objective is to develop a novel tool for the analysis of the Swiss electricity system. This study illustrates the capabilities of Nexus-e in answering the crucial questions of how centralized and distributed flexibility technologies could be deployed in the Swiss electricity system and how they would impact the traditional operation of the system. The aim of the analysis is not policy advice, as some critical developments like the European net-zero emissions goal are not yet included in the scenarios, but rather to illustrate the unique capabilities of the Nexus-e modeling framework. To answer these questions, consistent technical representations of a wide spectrum of current and novel energy supply, demand, and storage technologies are needed as well as a thorough economic evaluation of different investment incentives and the impact investments have on the wider economy. Moreover, these aspects need to be combined with modeling of the long- and short-term electricity market structures and electricity networks. This report illustrates the capabilities of the Nexus-e platform.

The Nexus-e Platform consists of five interlinked modules:

1. General Equilibrium Module for Electricity (GemEl): a computable general equilibrium (CGE) module of the Swiss economy,
2. Centralized Investments Module (CentIv): a grid-constrained generation expansion planning (GEP) module considering system flexibility requirements,
3. Distributed Investments Module (DistIv): a GEP module of distributed energy resources,
4. Electricity Market Module (eMark): a market-based dispatch module for determining generator production schedules and electricity market prices,
5. Network Security and Expansion Module (Cascades): a power system security assessment and transmission system expansion planning module.

This report describes the validation and calibration of the different modules within the Nexus-e framework. The objectives of the validation and the calibration of the Nexus-e modules is to develop trustworthy and high-fidelity modules as well as to adjust the modules to better represent the complexity of the involved real systems and processes.

Zusammenfassung

Politische Veränderungen im Energiesektor haben weitreichende Auswirkungen auf das gesamte Energiesystem und beeinflussen alle Sektoren der Wirtschaft. Aufgrund der hohen Komplexität der Energiewirtschaft, wurden bisher nur wenige Versuche unternommen, die Wechselwirkungen zwischen den einzelnen Komponenten dieses Systems zu modellieren. Nexus-e, eine Plattform für die Modellierung von integrierten Energiesystemen, schliesst diese Lücke und schafft einen interdisziplinäre Plattform, in welcher verschiedene Module über klar definierten Schnittstellen miteinander verbunden sind. Dadurch können die Auswirkungen zukünftiger Entwicklungen in der Energiewirtschaft ganzheitlicher analysiert und verstanden werden. Die Nexus-e Plattform ermöglicht die Kombination von „Bottom-Up“ und „Top-Down“ Energiemodellen und ermöglicht es dadurch, einen breiteren Bereich der Energiewirtschaft abzubilden als dies bei traditionellen Modellierungsansätzen der Fall ist.

Phase 1 dieses Projekts zielt darauf ab, ein neuartiges Instrument für die Analyse des schweizerischen Elektrizitätssystems zu entwickeln. Um die Möglichkeiten von Nexus-e zu veranschaulichen, untersuchen wir die Frage, wie zentrale und dezentrale Flexibilitätstechnologien im schweizerischen Elektrizitätssystem eingesetzt werden können und wie sie sich auf den traditionellen Betrieb des Energiesystems auswirken würden. Ziel der Analyse ist es nicht Empfehlungen für die Politik zu geben, da einige wichtige Entwicklungen wie das Europäische Netto-Null-Emissionsziel noch nicht in den Szenarien enthalten sind. Vielmehr möchten wir die einzigartigen Fähigkeiten der Modellierungsplattform Nexus-e vorstellen. Um diese Fragen zu beantworten, ist eine konsistente technische Darstellungen aktueller und neuartiger Energieversorgungs-, Nachfrage- und Speichertechnologien, sowie eine gründliche wirtschaftliche Bewertung der verschiedenen Investitionsanreize und der Auswirkungen der Investitionen auf die Gesamtwirtschaft erforderlich. Darüber hinaus müssen diese Aspekte mit der Modellierung der lang- und kurzfristigen Strommarktstrukturen und Stromnetze kombiniert werden. Dieser Report veranschaulicht die Fähigkeiten der Nexus-e Plattform.

Die Nexus-e Plattform besteht aus fünf miteinander verknüpften Modulen:

1. Allgemeines Gleichgewichtsmodul für Elektrizität (GemEl): ein Modul zur Darstellung des allgemeinen Gleichgewichts (CGE) der Schweizer Wirtschaft,
2. Investitionsmodul für zentrale Energiesysteme (CentIv): ein Modul zur Planung des netzgebundenen Erzeugungsausbaus (GEP) unter Berücksichtigung der Anforderungen an die Systemflexibilität,
3. Investitionsmodul für dezentrale Energiesysteme (DistIv): ein GEP-Modul für dezentrale Energieerzeugung,
4. Strommarktmodul (eMark): ein marktorientiertes Dispatch-Modul zur Bestimmung von Generator-Produktionsplänen und Strommarktpreisen,
5. Netzsicherheits- und Erweiterungsmodul (Cascades): ein Modul zur Bewertung der Sicherheit des Energiesystems und zur Planung der Erweiterung des Übertragungsnetzes.

Dieser Bericht beschreibt die Validierung und Kalibrierung der verschiedenen Module im Rahmen von Nexus-e. Das Ziel der Validierung und Kalibrierung ist es, vertrauenswürdige und originalgetreue Module zu entwickeln und diese so anzupassen, dass sie die Komplexität der beteiligten realen Systeme und Prozesse besser repräsentieren.

Résumé

Les changements de politique dans le secteur de l'énergie ont de vastes répercussions sur l'ensemble du système énergétique et influencent tous les secteurs de l'économie. En partie à cause de la grande complexité de la combinaison de modèles séparés, peu de tentatives ont été entreprises pour modéliser les interactions entre les composantes du système économico-énergétique. La plateforme de modélisation des systèmes énergétiques intégrés Nexus-e vise à combler cette lacune en fournissant un cadre interdisciplinaire de modules qui sont reliés par des interfaces bien définies pour analyser et comprendre de manière holistique l'impact des développements futurs du système énergétique. Cette plateforme combine des approches de modélisation énergétique ascendante et descendante pour représenter un champ d'application beaucoup plus large du système économico-énergétique que les approches de modélisation indépendantes traditionnelles.

Dans la phase 1 de ce projet, l'objectif est de développer un nouvel outil pour l'analyse du système électrique suisse. Cette étude sert à illustrer les capabilités de Nexus-e à répondre aux questions cruciales de comment les technologies de flexibilité centralisées et décentralisées pourraient être déployées dans le système électrique suisse et comment elles affecteraient le fonctionnement traditionnel du système. Le but de cette analyse n'est pas d'offrir de conseils politiques, en tant que les scénarios ne considèrent pas des développements critiques comme l'objectif Européen d'atteindre zéro émission nette, mais d'illustrer les capabilités uniques de la plateforme Nexus. Pour répondre à ces questions, des représentations techniques cohérentes d'un large éventail de technologies actuelles et nouvelles d'approvisionnement, de demande et de stockage d'énergie sont nécessaires, ainsi qu'une évaluation économique approfondie des différentes incitations à l'investissement et de l'impact des investissements sur l'économie au sens large. En outre, ces aspects doivent être combinés avec la modélisation des structures du marché de l'électricité et des réseaux d'électricité à long et à court terme. Ce rapport illustre les capacités de la plateforme Nexus-e.

La plateforme Nexus-e se compose de cinq modules interconnectés:

1. Module d'équilibre général pour l'électricité (GemEl) : un module d'équilibre général calculable (CGE) de l'économie suisse,
2. Module d'investissements centralisés (CentIv) : un module de planification de l'expansion de la production (GEP) soumise aux contraintes du réseau, qui tient compte des exigences de flexibilité du système,
3. Module d'investissements distribués (DistIv) : un module GEP de la production décentralisée d'énergie,
4. Module du marché de l'électricité (eMark) : un module de répartition basé sur le marché pour déterminer les calendriers de production des producteurs et les prix du marché de l'électricité,
5. Module de sécurité et d'expansion du réseau (Cascades) : un module d'évaluation de la sécurité du système électrique et de planification de l'expansion du système de transmission.

Ce rapport décrit la validation et la calibration des différents modules dans le cadre de Nexus-e. L'objectif de la validation et de la calibration des modules Nexus-e est de gagner en confiance dans les modules ainsi que d'ajuster les modules pour mieux représenter la complexité des systèmes et des processus réels concernés.

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1 Introduction

1.1 Module purpose

The Distributed Investments Module aims to jointly optimize the investments and operations of a distribution system to satisfy the demand and policy targets while minimizing total costs, considering potential trading of energy and reserve with the transmission system. The components considered in the distribution system include distributed energy resources such as storage units, demand response programs, variable and dispatchable generation units.

1.2 Process overview

The Distributed Investments Module (DistIv) module optimizes the investment decisions of distributed energy resources over a one year period using an hourly resolution. Given the electricity prices from Centralized Investments Module (CentIv), the model makes the trade-off between investing in local distributed energy resources and purchasing electricity from the transmission grid. The trade-off is realized by jointly optimizing the investments and operations of a distribution system considering different types of storage units, variable and dispatchable generation units and demand response programs, while taking the exchange with the transmission system into consideration. To reduce the computational time, every other day instead of all hours of the year is simulated.

1.3 Attributes

The following list characterizes some of the main module attributes:

- Hourly resolution;
- Computation time reduced by simulating every x days (e.g. x = 2 means that 183 instead 365 days are considered for the simulation);
- Co-optimization of multiple regions;
- Modeled market structure consists of both energy and reserve markets;
- Investment potentials of photovoltaic (PV) are considered for different PV sizes, cantons, and irradiation levels;
- A green-field investment is modeled, i.e. no existing units considered in the distribution system.

1.4 Capabilities

The following list describes some of the main capabilities of this module:

- Co-optimization of the investment decisions of multiple regions while satisfying a common renewable energy target;
- Optimization of the investment decisions of different distributed energy resources considering their participation in both energy and reserve markets;
- Modeling of demand response programs;
- Incorporation of PV-battery and demand response into the modeling of PV self-consumption rate;
- Incorporation of future reserve products (e.g. shorter reserve provisioning time).

1.5 Limitations

The following list provides some of the main limitations of this module:

- Distribution grid is not considered;
- Simple reserve bidding model (no differentiation between different reserve products, reserve deployment not considered);
- Electric vehicles are not considered;

1.6 Inputs and outputs

Tables 1 and 2 below list the required input of the DistIv module and resulting output data. Those data that are input from or sent to another module through an interface are noted with an asterisk (*).

Table 1: Listing of required input data for DistIv module.

Data	Resolution	Unit	Description
Original Demand*	hourly, by region	MW	Original transmission system demand
Electricity Price*	hourly, by region	CHF/MWh	Hourly wholesale electricity price
Secondary Reserve Price*	hourly	CHF/MWh	Hourly secondary reserve price
Secondary System Reserve Req.*	hourly	MW	System secondary up/down reserve requirement
Residual RES Target*	annual	TWh	Residual target for production from non-hydro RES
Grid Tariff	by region	CHF/MWh	Tariff paid for the grid usage
Subsidy information	by unit, by region	n/a	Subsidy policy of each unit type in different regions
Irradiation data	hourly, by region	kWh/kWp	Annual irradiation level per square meter
Demand Response Limits	hourly or daily	n/a	Power and energy constraints for the demand shift
Distributed Generation Unit Data	by unit	n/a	Technical, economic, investment potential etc. of each unit type

Table 2: Listing of resulting output data for DistIv module.

Data	Resolution	Unit	Description
Residual Demand*	hourly, by region	MW	Residual demand (original demand minus distributed generation and demand-side management (DSM)/battery storage system (BSS) load shifting)
DistIv Generation*	hourly, by region	MW	Generation from units in the distribution system
Residual Secondary System Reserve Req.*	hourly	MW	Residual hourly system secondary up/down reserve requirement
RES Generation*	annual	TWh	Total renewable generation in DistIv
Non-dispatchable Distributed Capacity*	annual, by unit	MW	Accumulated non-dispatchable investments per technology in DistIv
Costs of Existing and Invested Units*	annual, by unit	CHF	Investment and operating costs of each unit type
Investment	by unit, by region	MW	Regional investment capacity decisions for each unit type
Demand Response Dispatch	hourly, by region	MW	Hourly dispatch of demand shifting

2 Related work and contributions

While a significant amount of work has been done in terms of investment planning in the past, traditional distribution planning models mainly focus on optimizing network topology, the size of dispatchable generation units, the size of substations, feeders and/or transformers, e.g. [1] and [2]. With the increasing penetration of distributed resources such as storage devices, PV and wind generation and demand response (DR) programs in recent years, modern models are more complex and focus on one or the coordinated planning of several distributed energy resources (DER) technologies. For example, [3] and [4] investigated the effects of electric vehicles' penetrations. References [5] and [6] focus on the integration of demand response programs, while [7] and [8] consider the incorporation of both demand response programs and storage investments. In [9, 10, 11], approaches for planning and operating renewable energies and storage devices are proposed whereas in [12] a planning method to decide on optimal locations, sizes and mix of both dispatchable and intermittent distributed generation is presented, with renewable outputs' uncertainties incorporated using robust optimization. The authors of [13] proposed a method that considers a comprehensive configuration of microgrids with demand-side management, but the candidate technologies are limited to solar, wind and battery. As a result, most of the existing models only target the optimization of investment decisions considering limited options of candidate technologies and without considering their participation in electricity markets. However, because of the uncertain nature of variable generation outputs, it is important to consider the coordination of different units already in the planning phase to support their integration. Furthermore, as DERs are expected to participate in markets in the future and contribute flexibility, it is important to consider their market participation to exploit the economic value of DER investments. Note that DERs are assumed to be price-takers since the market exchange is limited by the transmission capacity between the distribution and the transmission system.

As mentioned earlier, the focus of this work is on joint investment and operation optimization of DERs, considering their participation in both energy and reserve markets.

Consequently, the contributions of this work are:

1. To propose a multi-stage programming model that jointly optimizes the investments and operations of a distribution system considering different types of storage units, variable and dispatchable generation units and demand response programs.
2. To model the market environment and analyze its impact on investment and operation decisions.
3. To validate the model using Swiss data.
4. To analyze the effects of demand response program participation.
5. To construct a detailed PV investment decision-making model by considering investment behaviors of different PV unit categories, irradiation levels and regions.
6. To integrate the PV-battery and the demand response into the modeling of the self-consumption of PV.
7. To consider the trade-off between investing in distributed energy resources and purchasing electricity from the transmission system.

3 Detailed module description

3.1 Problem description

In this document, questions concerning the optimal distributed generation mix for a distribution system are addressed, considering DERs' participation in reserve and energy markets. The target country (Switzerland) is split into different regions and each region is considered as an aggregator. The aggregator which can also be a distribution system operator, is modeled as a cluster of storage devices, loads, dispatchable and variable generation units.

The structure of the proposed multi-stage optimization model is set up as follows:

- 1st stage: The aggregator optimizes the investment decisions for the examined year (i.e. how much should be invested into each type of units) taking constraints such as the available resource potential and the previous investments into consideration.
- 2nd stage: The short-term operation stage consists of two periods, corresponding to two markets: reserve and energy markets. Following a realistic market structure, the aggregator first decides its bids into the reserve market and then to the energy market.

The objective is to minimize the combined costs of all stages. The structure of a sample aggregator is shown in Fig.1. The system is split into two parts, represented by two dotted squares, while the left square indicates the PV-battery (PVB) system, the right one includes other system components that are directly connected to the grid. The arrows show the directions of the power flow.

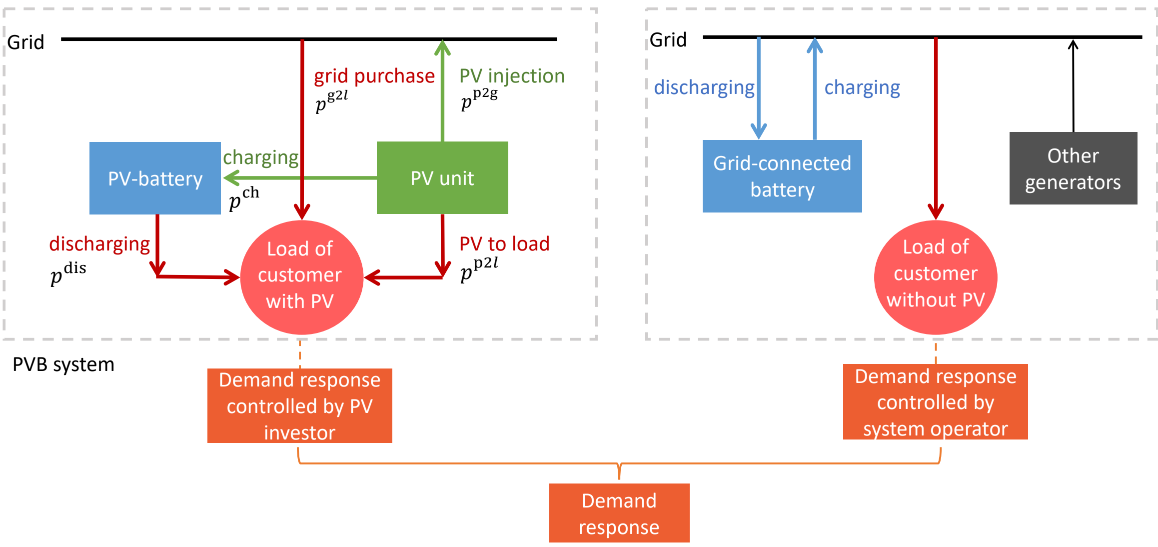

Figure 1: Structure of one sample aggregator.

3.2 Mathematical formulation

This section describes the main mathematical formulations considered in the DistIv module. The considered system is divided into regions $reg \in REG$ (in the case study corresponding to the cantons in

Switzerland). Each region is modeled as an aggregated node connected to the transmission system.

3.2.1 Constraints modeling

To optimize the investment and operation decisions, five groups of constraints are considered: 1) investment constraints, 2) operation constraints 3) power balance of the system, 4) market constraints, and 5) policy constraints. The operation constraints are further split into the constraints for components inside the PV system and the components outside the PV system. All grid-connected units are assumed to participate in the energy market and all grid-connected units except variable generation units are assumed to have access to the reserve market. Note that as revenues from reserve deployment are comparably low, only the reserve commitment phase is considered in this work. Reserve provision by variable generation units such as PV generation through curtailments, while omitted here, could be considered using formulations similar to other units. Network constraints are not considered in this work.

Investment constraint In year $y \in Y$, for each region $reg \in REG$ the investment capacity $x^{\text{inv}}_{i,reg,y,lev}$ in candidate unit type $i \in I$ with output level lev are limited by the maximum potential capacity for deployment measured in the initial simulation year minus the investments made from the initial until the current simulation year, where I, REG and Y are the set of considered unit types, regions and years:

$$0 \leq x^{\text{inv}}_{i,reg,y,lev} \leq dep^{\text{max}}_{i,reg,lev} - \sum_{y'=y_0}^{y'=y-1} x^{\text{exist}}_{i,reg,y',lev} \tag{1}$$

$$x^{\text{inv}}_{i,reg,y} = \sum_{lev=1}^{lev=N^{\text{lev}}_i} x^{\text{inv}}_{i,reg,y,lev} \tag{2}$$

$$x^{\text{exist}}_{i,reg,y} = \sum_{lev=1}^{lev=N^{\text{lev}}_i} \sum_{y'=y_0}^{y'=y-1} x^{\text{inv}}_{i,reg,y',lev} \tag{3}$$

where $dep^{\text{max}}_{i,reg,lev}$ is the initial potential for deployment in region reg for output level lev in the initial simulation year y_0 and $x^{\text{exist}}_{i,reg,y,lev}$ is the existing capacity in the current simulation year y. And lev is an integer ranging from 1 to N^{lev}_i where N^{lev}_i is the number of output levels for unit i. N^{lev}_i equals to one for all units except PVs, whose potentials are considered with respect to different irradiation levels and the N^{lev}_i equals the number of considered irradiation levels. For simplification purposes, in the following formulations index lev is ignored for all units except PV.

Operation constraints for units and demand outside the PV system The planned distribution system outside the PV system consists of four different categories of components, namely dispatchable generation units, variable generation units except PV, grid-connected storage units and loads (including elastic and inelastic).

Dispatchable generation unit We use G to indicate the set of dispatchable generation unit categories. The power output $P_{g,t,reg}$ at time t of newly invested dispatchable generation unit type g in region reg is non-negative and limited by its invested capacity in the current year $x^{\text{inv}}_{g,reg}$. The increase or reduction in output per unit time is limited by the maximum ramp rate $x^{\text{inv}}_{g,reg} r^{\text{max}}_g$ where r^{max}_g is presented as a percentage of the capacity. Mathematically,

$$0 \leq P_{g,t,reg} \leq x^{\text{inv}}_{g,reg} \tag{4}$$

$$0 \leq P_{g,t,reg} + RU_{g,t,reg} - RD_{g,t,reg} \leq x^{\text{inv}}_{g,reg} \tag{5}$$

$$P_{g,t,reg} - P_{g,t-1,reg} + RU_{g,t,reg} \leq x^{\text{inv}}_{g,reg} r^{\text{max}}_{g} \tag{6}$$

$$P_{g,t-1,reg} - P_{g,t,reg} + RD_{g,t,reg} \leq x^{\text{inv}}_{g,reg} r^{\text{max}}_{g} \tag{7}$$

where $g \in G$, $RU_{g,t,reg}$ and $RD_{g,t,reg}$ are up- and down-regulation capacities bidding into the reserve market. Similarly, constraints for existing dispatchable generation units are as follows:

$$0 \leq P^{\text{exist}}_{g,t,reg} \leq x^{\text{exist}}_{g,reg} \tag{8}$$

$$0 \leq P^{\text{exist}}_{g,t,reg} + RU^{\text{exist}}_{g,t,reg} - RD^{\text{exist}}_{g,t,reg} \leq x^{\text{exist}}_{g,reg} \tag{9}$$

$$P^{\text{exist}}_{g,t,reg} - P^{\text{exist}}_{g,t-1,reg} + RU^{\text{exist}}_{g,t,reg} \leq x^{\text{exist}}_{g,reg} r^{\text{max}}_{g} \tag{10}$$

$$P^{\text{exist}}_{g,t-1,reg} - P^{\text{exist}}_{g,t,reg} + RD^{\text{exist}}_{g,t,reg} \leq x^{\text{exist}}_{g,reg} r^{\text{max}}_{g} \tag{11}$$

where $x^{\text{exist}}_{g,reg}$ is the current existing capacity of unit type g in region reg.

Variable generation unit (except PV) Let V denote the set of all candidate variable generation units, the power output of newly invested variable generation $P_{v,t,reg}$ is non-negative and limited by the product of the generation forecasts in percentage $p^{\text{f}}_{v,t,reg,lev}$ at potential level lev and the invested capacity $x^{\text{inv}}_{v,reg,lev}$. Similarly, the output $P^{\text{exist}}_{v,t,reg,y'}$ of existing variable generation unit v that was invested in year y' is non-negative and limited by the product of the generation forecasts in percentage $p^{\text{f}}_{v,t,reg,lev}$ and the capacity invested for the corresponding year, which is calculated by $(x^{\text{exist}}_{v,reg,y'+1,lev} - x^{\text{exist}}_{v,reg,y',lev})$.

$$0 \leq P_{v,t,reg} \leq \sum_{lev=1}^{lev=N^{\text{lev}}_{v}} x^{\text{inv}}_{v,reg,lev} p^{\text{f}}_{v,t,reg,lev} \tag{12}$$

$$0 \leq P^{\text{exist}}_{v,t,reg,y'} \leq \sum_{lev=1}^{lev=N^{\text{lev}}_{v}} (x^{\text{exist}}_{v,reg,y'+1,lev} - x^{\text{exist}}_{v,reg,y',lev}) p^{\text{f}}_{v,t,reg,lev} (1 - age_{y'} \beta^{\text{deg}}_{v}) \tag{13}$$

$$P^{\text{exist}}_{v,t,reg} = \sum_{y'=y_0}^{y'=y-1} P^{\text{exist}}_{v,t,reg,y'} \tag{14}$$

where $v \in V$. β^{deg}_{v} indicates the annual degradation rate of unit v while $age_{y'}$ is the age of the unit calculated by the current simulation year y minus the invested year y'. The curtailment costs are assumed to be zero.

Grid-connected storage unit We denote the set of the grid-connected storage units by S and the minimum and maximum energy stored in storage unit category s as a percentage of the capacity of the storage by E^{min}_{s} and E^{max}_{s}, while the maximum inflow and outflow rates of the storage are indicated by

$P_s^{\text{ch,max}}$ and $P_s^{\text{dis,max}}$, respectively. This results in the following set of equations:

$$\begin{aligned} E_s^{\text{min}} x_{s,reg}^{\text{inv}} \leq E_{s,t,reg} &\leq E_s^{\text{max}} x_{s,reg}^{\text{inv}} && (15)\\ 0 \leq P_{s,t,reg}^{\text{ch}} &\leq P_s^{\text{ch,max}} x_{s,reg}^{\text{inv}} && (16)\\ 0 \leq P_{s,t,reg}^{\text{dis}} &\leq P_s^{\text{dis,max}} x_{s,reg}^{\text{inv}} && (17)\\ P_{s,t,reg}^{\text{ch}} - P_{s,t,reg}^{\text{dis}} + RD_{s,t,reg} &\leq P_s^{\text{ch,max}} x_{s,reg}^{\text{inv}} && (18)\\ P_{s,t,reg}^{\text{dis}} - P_{s,t,reg}^{\text{ch}} + RU_{s,t,reg} &\leq P_s^{\text{dis,max}} x_{s,reg}^{\text{inv}} && (19)\\ 0 \leq P_{s,t}^{\text{ch}} &\leq M u_{s,t} && (20)\\ 0 \leq P_{s,t}^{\text{dis}} &\leq M(1-u_{s,t}) && (21)\\ & && (22) \end{aligned}$$

where $E_{s,t,reg}$, $P_{s,t,reg}^{\text{ch}}$ and $P_{s,t,reg}^{\text{dis}}$ are the stored energy, inflow and outflow of the storage unit s at time t in region reg. $u_{s,t}$ is a binary variable indicating charging/discharging status and M is a big value. $RU_{s,t,reg}$ and $RD_{s,t,reg}$ are the non-negative up- and down-reserve bidding quantities. Finally, the relationship of storage levels for two consecutive time steps is defined by

$$E_{s,t,reg} = E_{s,t-1,reg} + \eta_s P_{s,t,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,t,reg}^{\text{dis}} \Delta_t - \zeta_s E_{s,t-1,reg} \tag{23}$$

where η_s and ζ_s are the conversion efficiency and the self-discharging rate of storage unit s, and Δ_t is one hour. To lower the computational burden, only limited number of days are simulated. These representative days are selected every n_d days from the beginning of the simulation year and the days in between are assumed to follow the same dispatch as the latest simulated day. For example, if simulations are done every two days (i.e. $n_d = 2$), then the first day, the third day, the fifth day, etc. are simulated while the second day, the fourth day, etc. are assumed to have the same dispatch as the first day, the third, etc. Thus, additional constraints should be applied to the first hour of all simulation days except the first simulation day to take the operations of the days that are not simulated in between into consideration:

$$\begin{aligned} E_{s,TT(ii-1)+1,reg} =& (1-\zeta_s)[E_{s,TT(ii-1),reg} + (E_{s,TT(ii-1),reg} - E_{s,TT(ii-2)+1,reg} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis}}) \Delta_t (n_d - 1)] \\ &+ \eta_s P_{s,TT(ii-1)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-1)+1,reg}^{\text{dis}} \Delta_t \end{aligned} \tag{24}$$

where TT is the total number of hours (i.e. 24) of a day. The index of each simulation day is indicated by ii with $ii = 2, 3, ..., \lceil \frac{N_d}{n_d} \rceil$, where N_d is the total number of days of the simulation year. Furthermore, the following constraints limit the storage levels of the first and the last hour of the days that are not simulated to be within the minimum and the maximum storage level.

$$\begin{aligned} E_s^{\text{min}} x_{s,reg}^{\text{inv}} \leq& (1-\zeta_s) E_{s,TT(ii-1),reg} + \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t && (25)\\ E_s^{\text{max}} x_{s,reg}^{\text{inv}} \geq& (1-\zeta_s) E_{s,TT(ii-1),reg} + \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t && (26)\\ E_s^{\text{min}} x_{s,reg}^{\text{inv}} \leq& E_{s,TT(ii-1),reg} + (E_{s,TT(ii-1),reg} - E_{s,TT(ii-2)+1,reg} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t)(n_d - 1) && (27)\\ E_s^{\text{max}} x_{s,reg}^{\text{inv}} \geq& E_{s,TT(ii-1),reg} + (E_{s,TT(ii-1),reg} - E_{s,TT(ii-2)+1,reg} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t)(n_d - 1) && (28) \end{aligned}$$

Similarly, corresponding constraints for existing storage units are as follows:

$$E_s^{\text{min}} x_{s,reg}^{\text{exist}} \leq E_{s,t,reg}^{\text{exist}} \leq E_s^{\text{max}} x_{s,reg}^{\text{exist}} \tag{29}$$

$$0 \leq P_{s,t,reg}^{\text{ch,exist}} \leq P_s^{\text{ch,max}} x_{s,reg}^{\text{exist}} \tag{30}$$

$$0 \leq P_{s,t,reg}^{\text{dis,exist}} \leq P_s^{\text{dis,max}} x_{s,reg}^{\text{exist}} \tag{31}$$

$$P_{s,t,reg}^{\text{ch,exist}} - P_{s,t,reg}^{\text{dis,exist}} + RD_{s,t,reg}^{\text{exist}} \leq P_s^{\text{ch,max}} x_{s,reg}^{\text{exist}} \tag{32}$$

$$P_{s,t,reg}^{\text{dis,exist}} - P_{s,t,reg}^{\text{ch,exist}} + RU_{s,t,reg}^{\text{exist}} \leq P_s^{\text{dis,max}} x_{s,reg}^{\text{exist}} \tag{33}$$

$$E_{s,t,reg}^{\text{exist}} = E_{s,t-1,reg}^{\text{exist}} + \eta_s P_{s,t,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,t,reg}^{\text{dis,exist}} \Delta_t - \zeta_s E_{s,t-1,reg}^{\text{exist}} \tag{34}$$

$$0 \leq P_{s,t}^{\text{ch,exist}} \leq M u_{s,t}^{\text{exist}} \tag{35}$$

$$0 \leq P_{s,t}^{\text{dis,exist}} \leq M(1 - u_{s,t}^{\text{exist}}) \tag{36}$$

$$\begin{aligned} E_{s,TT(ii-1)+1,reg}^{\text{exist}} = (1-\zeta_s)[E_{s,TT(ii-1),reg}^{\text{exist}} &+ (E_{s,TT(ii-1),reg}^{\text{exist}} - E_{s,TT(ii-2)+1,reg}^{\text{exist}} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis,exist}}) \Delta_t (n_d - 1)] \\ &+ \eta_s P_{s,TT(ii-1)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-1)+1,reg}^{\text{dis,exist}} \Delta_t \end{aligned} \tag{37}$$

$$E_s^{\text{min}} x_{s,reg}^{\text{exist}} \leq (1-\zeta_s) E_{s,TT(ii-1),reg}^{\text{exist}} + \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis,exist}} \Delta_t \tag{38}$$

$$E_s^{\text{max}} x_{s,reg}^{\text{exist}} \geq (1-\zeta_s) E_{s,TT(ii-1),reg}^{\text{exist}} + \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis,exist}} \Delta_t \tag{39}$$

$$\begin{aligned} E_s^{\text{min}} x_{s,reg}^{\text{exist}} \leq E_{s,TT(ii-1),reg}^{\text{exist}} &+ (E_{s,TT(ii-1),reg}^{\text{exist}} - E_{s,TT(ii-2)+1,reg}^{\text{exist}} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis,exist}} \Delta_t)(n_d - 1) \end{aligned} \tag{40}$$

$$\begin{aligned} E_s^{\text{max}} x_{s,reg}^{\text{exist}} \geq E_{s,TT(ii-1),reg}^{\text{exist}} &+ (E_{s,TT(ii-1),reg}^{\text{exist}} - E_{s,TT(ii-2)+1,reg}^{\text{exist}} \\ &+ \eta_s P_{s,TT(ii-2)+1,reg}^{\text{ch,exist}} \Delta_t - \eta_s^{-1} P_{s,TT(ii-2)+1,reg}^{\text{dis,exist}} \Delta_t)(n_d - 1) \end{aligned} \tag{41}$$

where $ii \in [2, 3, ..., \lceil \frac{N_d}{n_d} \rceil]$.

Load For consumers without PV, as part of their load is elastic, it is assumed that they participate in the demand response program and their load shifting can be fully controlled by the system operator. The initial estimation of the load of these consumers in region reg is $P_{t,reg}^{\text{L,est,npv}}$ and their final scheduled load profile is given by

$$P_{t,reg}^{\text{L,sch,npv}} = P_{t,reg}^{\text{L,est,npv}} + r_{t,reg}^{\text{L+,npv}} - r_{t,reg}^{\text{L-,npv}} \tag{42}$$

where $r_{t,reg}^{\text{L+,npv}}$ and $r_{t,reg}^{\text{L-,npv}}$ indicate the load increase and decrease for consumers without PV for time step t in region reg. These values are determined based on the maximum power and energy allowed to be shifted for elastic demand of consumers without PV for each region denoted by $L_{reg}^{\text{sh,max,npv}}$ and $E_{reg}^{\text{sh,max,npv}}$, respectively. Mathematically, $r_{t,reg}^{\text{L+,npv}}$ and $r_{t,reg}^{\text{L-,npv}}$ are limited by the following constraints:

$$0 \leq r_{t,reg}^{\text{L+,npv}} \leq L_{reg}^{\text{sh,max,npv}} \tag{43}$$

$$0 \leq r_{t,reg}^{\text{L-,npv}} \leq L_{reg}^{\text{sh,max,npv}} \tag{44}$$

$$r_{t,reg}^{\text{L+,npv}} - r_{t,reg}^{\text{L-,npv}} + RD_{t,reg}^{\text{L}} \leq L_{reg}^{\text{sh,max,npv}} \tag{45}$$

$$r_{t,reg}^{\text{L-,npv}} - r_{t,reg}^{\text{L+,npv}} + RU_{t,reg}^{\text{L}} \leq L_{reg}^{\text{sh,max,npv}} \tag{46}$$

$$\sum_{t=t_0}^{t_0+24} (r_{t,reg}^{\text{L+,npv}} + r_{t,reg}^{\text{L-,npv}}) \leq E_{reg}^{\text{sh,max,npv}} \tag{47}$$

where t_0 is the starting time point for each simulation day, $RU_{t,reg}^{\text{L}}$ and $RD_{t,reg}^{\text{L}}$ are non-negative up- and down-reserve bidding quantities. Additionally, it is required that the energy consumption during each day should not be changed:

$$\sum_{t=t_0}^{t_0+24} (r^{\text{L+}}_{t,reg} - r^{\text{L-}}_{t,reg}) = 0 \tag{48}$$

As mentioned, it is assumed that the load participating in the DR program can be fully controlled by the aggregator, however, as this is not true in reality, a discomfort cost is therefore considered for which the formulation is described in the next section.

Operation constraint for the PV system The PV system shown in Fig. 2 is composed of PV units, PV-batteries and loads of the PV investor (including elastic and inelastic). Constraints for the three components are described in the following paragraphs.

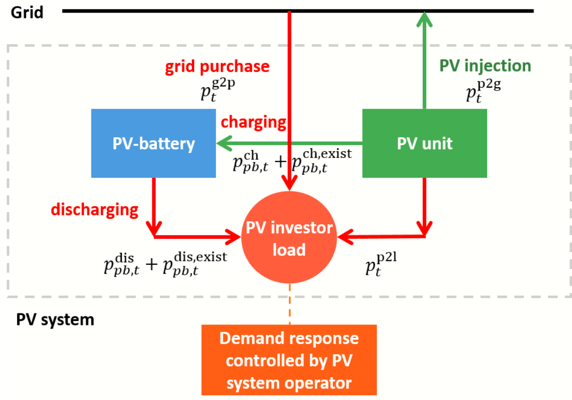

Figure 2: Structure of the PV system.

PV unit Let P denote the set of all candidate PV units, as $P \in V$, constraints (12)-(14) are also applicable to PV units, i.e.

$$0 \leq P_{p,t,reg} \leq \sum_{lev=1}^{N_p^{\text{lev}}} x^{\text{inv}}_{p,reg,lev} p^{\text{f}}_{p,t,reg,lev} \tag{49}$$

$$0 \leq P^{\text{exist}}_{p,t,reg,y'} \leq \sum_{lev=1}^{N_p^{\text{lev}}} (x^{\text{exist}}_{p,reg,y'+1,lev} - x^{\text{exist}}_{p,reg,y',lev}) p^{\text{f}}_{p,t,reg,lev} (1 - age_{y'} \beta_p^{\text{deg}}) \tag{50}$$

$$P^{\text{exist}}_{p,t,reg} = \sum_{y'=y_0}^{y'=y-1} P^{\text{exist}}_{p,t,reg,y'} \tag{51}$$

where $p \in P$.

PV-battery unit The operations of the PV-battery unit are similar to the grid-connected storage units. However, the PV-battery has no connection to the grid and in general it charges (discharges) when the demand of the PV investor is lower (higher) than the PV generation. We denote the set of the PV-battery units by PB and the minimum and maximum energy stored in storage unit pb as a percentage of the capacity of the storage by E^{min}_{pb} and E^{max}_{pb}, while the maximum inflow and outflow rates of the storage are indicated by $P^{\text{ch,max}}_{pb}$ and $P^{\text{dis,max}}_{pb}$, respectively. This results in the following set of equations:

$$E_{pb}^{\text{min}} x_{pb,reg}^{\text{inv}} \leq E_{pb,t,reg} \leq E_{pb}^{\text{max}} x_{pb,reg}^{\text{inv}} \tag{52}$$
$$0 \leq P_{pb,t,reg}^{\text{ch}} \leq P_{pb}^{\text{ch,max}} x_{pb,reg}^{\text{inv}} \tag{53}$$
$$0 \leq P_{pb,t,reg}^{\text{dis}} \leq P_{pb}^{\text{dis,max}} x_{pb,reg}^{\text{inv}} \tag{54}$$
$$P_{pb,t,reg}^{\text{ch}} - P_{pb,t,reg}^{\text{dis}} \leq P_{pb}^{\text{ch,max}} x_{pb,reg}^{\text{inv}} \tag{55}$$
$$P_{pb,t,reg}^{\text{dis}} - P_{pb,t,reg}^{\text{ch}} \leq P_{pb}^{\text{dis,max}} x_{pb,reg}^{\text{inv}} \tag{56}$$
$$0 \leq P_{pb,t}^{\text{ch}} \leq M u_{pb,t} \tag{57}$$
$$0 \leq P_{pb,t}^{\text{dis}} \leq M(1 - u_{pb,t}) \tag{58}$$
$$\tag{59}$$

where $E_{pb,t,reg}$, $P_{pb,t,reg}^{\text{ch}}$ and $P_{pb,t,reg}^{\text{dis}}$ are the stored energy, inflow and outflow of the PV-battery unit pb at time t in region reg. $u_{pb,t}$ is a binary variable indicating charging/discharging status and M is a big value. Finally, the relationship of storage levels for two consecutive time steps is defined by

$$E_{pb,t,reg} = E_{pb,t-1,reg} + \eta_{pb} P_{pb,t,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,t,reg}^{\text{dis}} \Delta_t - \zeta_{pb} E_{pb,t-1,reg} \tag{60}$$

where η_{pb} and ζ_{pb} are the conversion efficiency and the self-discharging rate of the PV-battery pb.

When limited number of days are simulated, additional constraints are applied to the first hour of all simulation days except the first day to consider the dispatch of the days in between that are not simulated:

$$\begin{aligned} E_{pb,TT(ii-1)+1,reg} =& (1 - \zeta_{pb})[E_{pb,TT(ii-1),reg} + (E_{pb,TT(ii-1),reg} - E_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P_{pb,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t)(n_d - 1)] \\ &+ \eta_{pb} P_{pb,TT(ii-1)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-1)+1,reg}^{\text{dis}} \Delta_t \end{aligned} \tag{61}$$

where $ii \in [2, 3, ..., \lceil \frac{N_d}{n_d} \rceil]$. The storage levels of the first and the last hour of the days that are not simulated are limited to be within the minimum and the maximum storage level by constraints (62)-(65).

$$E_{pb}^{\text{min}} x_{pb,reg}^{\text{inv}} \leq (1 - \zeta_{pb}) E_{pb,TT(ii-1),reg} + \eta_{pb} P_{pb,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t \tag{62}$$
$$E_{pb}^{\text{max}} x_{pb,reg}^{\text{inv}} \geq (1 - \zeta_{pb}) E_{pb,TT(ii-1),reg} + \eta_{pb} P_{pb,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t \tag{63}$$
$$\begin{aligned} E_{pb}^{\text{min}} x_{pb,reg}^{\text{inv}} \leq& E_{pb,TT(ii-1),reg} + (E_{pb,TT(ii-1),reg} - E_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P_{pb,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t)(n_d - 1) \end{aligned} \tag{64}$$
$$\begin{aligned} E_{pb}^{\text{max}} x_{pb,reg}^{\text{inv}} \geq& E_{pb,TT(ii-1),reg} + (E_{pb,TT(ii-1),reg} - E_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P_{pb,TT(ii-2)+1,reg}^{\text{ch}} \Delta_t - \eta_{pb}^{-1} P_{pb,TT(ii-2)+1,reg}^{\text{dis}} \Delta_t)(n_d - 1) \end{aligned} \tag{65}$$

The corresponding constraints for existing PV-batteries are as follows:

$$E^{\text{min}}_{pb} x^{\text{exist}}_{pb,reg} \leq E^{\text{exist}}_{pb,t,reg} \leq E^{\text{max}}_{pb} x^{\text{exist}}_{pb,reg} \tag{66}$$

$$0 \leq P^{\text{ch,exist}}_{pb,t,reg} \leq P^{\text{ch,max}}_{pb} x^{\text{exist}}_{pb,reg} \tag{67}$$

$$0 \leq P^{\text{dis,exist}}_{pb,t,reg} \leq P^{\text{dis,max}}_{pb} x^{\text{exist}}_{pb,reg} \tag{68}$$

$$P^{\text{ch,exist}}_{pb,t,reg} - P^{\text{dis,exist}}_{pb,t,reg} \leq P^{\text{ch,max}}_{pb} x^{\text{exist}}_{pb,reg} \tag{69}$$

$$P^{\text{dis,exist}}_{pb,t,reg} - P^{\text{ch,exist}}_{pb,t,reg} \leq P^{\text{dis,max}}_{pb} x^{\text{exist}}_{pb,reg} \tag{70}$$

$$E^{\text{exist}}_{pb,t,reg} = E^{\text{exist}}_{pb,t-1,reg} + \eta_s P^{\text{ch,exist}}_{pb,t,reg} \Delta_t - \eta_s^{-1} P^{\text{dis,exist}}_{pb,t,reg} \Delta_t - \zeta_s E^{\text{exist}}_{pb,t-1,reg} \tag{71}$$

$$0 \leq P^{\text{ch,exist}}_{pb,t} \leq M u^{\text{exist}}_{pb,t} \tag{72}$$

$$0 \leq P^{\text{dis,exist}}_{pb,t} \leq M(1 - u^{\text{exist}}_{pb,t}) \tag{73}$$

$$\begin{aligned} E^{\text{exist}}_{pb,TT(ii-1)+1,reg} = (1-\zeta_{pb})[E^{\text{exist}}_{pb,TT(ii-1),reg} &+ (E^{\text{exist}}_{pb,TT(ii-1),reg} - E^{\text{exist}}_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t)(n_d - 1)] \\ &+ \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-1)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-1)+1,reg} \Delta_t \end{aligned} \tag{74}$$

$$E^{\text{min}}_{pb} x^{\text{exist}}_{pb,reg} \leq (1-\zeta_{pb}) E^{\text{exist}}_{pb,TT(ii-1),reg} + \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t \tag{75}$$

$$E^{\text{max}}_{pb} x^{\text{exist}}_{pb,reg} \geq (1-\zeta_{pb}) E^{\text{exist}}_{pb,TT(ii-1),reg} + \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t \tag{76}$$

$$\begin{aligned} E^{\text{min}}_{pb} x^{\text{exist}}_{pb,reg} \leq E^{\text{exist}}_{pb,TT(ii-1),reg} &+ (E^{\text{exist}}_{pb,TT(ii-1),reg} - E^{\text{exist}}_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t)(n_d - 1) \end{aligned} \tag{77}$$

$$\begin{aligned} E^{\text{max}}_{pb} x^{\text{exist}}_{pb,reg} \geq E^{\text{exist}}_{pb,TT(ii-1),reg} &+ (E^{\text{exist}}_{pb,TT(ii-1),reg} - E^{\text{exist}}_{pb,TT(ii-2)+1,reg} \\ &+ \eta_{pb} P^{\text{ch,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t - \eta_{pb}^{-1} P^{\text{dis,exist}}_{pb,TT(ii-2)+1,reg} \Delta_t)(n_d - 1) \end{aligned} \tag{78}$$

Load For consumers with PV units, as it is more profitable for them to use the demand flexibility to increase the self-consumption rate of the PV, it is assumed that their elastic load is fully controlled by themselves and serves for improving the self-consumption rate of PV. The initial estimation of the load of consumers with PV installation in region reg is $P^{\text{L,est,pv}}_{t,reg}$ and the final scheduled load profile is given by

$$P^{\text{L,sch,pv}}_{t,reg} = P^{\text{L,est,pv}}_{t,reg} + r^{\text{L+,pv}}_{t,reg} - r^{\text{L-,pv}}_{t,reg} \tag{79}$$

where $r^{\text{L+,pv}}_{t,reg}$ and $r^{\text{L-,pv}}_{t,reg}$ indicate the load increase and decrease for consumers with PV for time step t in region reg. These values are determined based on the maximum power and energy allowed to be shifted for elastic demand of consumers with PV for each region denoted by $L^{\text{sh,max,pv}}_{reg}$ and $E^{\text{sh,max,pv}}_{reg}$, respectively. Mathematically, $r^{\text{L+,pv}}_{t,reg}$ and $r^{\text{L-,pv}}_{t,reg}$ are limited by the following constraints:

$$0 \leq r^{\text{L+,pv}}_{t,reg} \leq L^{\text{sh,max,pv}}_{reg} \tag{80}$$

$$0 \leq r^{\text{L-,pv}}_{t,reg} \leq L^{\text{sh,max,pv}}_{reg} \tag{81}$$

$$\sum_{t=t_0}^{t_0+24} (r^{\text{L+,pv}}_{t,reg} + r^{\text{L-,pv}}_{t,reg}) \leq E^{\text{sh,max,pv}}_{reg} \tag{82}$$

where t_0 is the starting time point for each simulation day. Additionally, it is required that the energy consumption during each day should not be changed:

$$\sum_{t=t_0}^{t_0+24} (r^{\text{L+}}_{t,reg} - r^{\text{L-}}_{t,reg}) = 0 \tag{83}$$

It is assumed that the load participating in the DR program can be fully controlled by the aggregator, however, as this is not true in reality, a discomfort cost is therefore considered for which the formulation is described in the next section.

Two kinds of power balance constraints including one for the PVB system and one for the overall region are enforced.

Power balance of the PV system As shown in Fig. 1, for the PVB system, the PV generation can be used for satisfying the load P^{p2l}, grid injection P^{p2g} or charging the PV-battery. Similarly, the PVB system's load (i.e. load of consumers with PV) can be met by the PV generation, the electricity from the grid P^{g2l} or the PV-battery discharge. Mathematically, Mathematically,

$$P_{p,t,reg} + P^{\text{exist}}_{p,t,reg} \geq P^{\text{p2l}}_{p,t,reg} + P^{\text{p2g}}_{p,t,reg} + P^{\text{ch}}_{pb,t,reg} + P^{\text{ch,exist}}_{pb,t,reg} \tag{84}$$

$$P^{\text{L,sch,pv}}_{p,t,reg} \leq P^{\text{p2l}}_{p,t,reg} + P^{\text{g2l}}_{p,t,reg} + P^{\text{dis}}_{pb,t,reg} + P^{\text{dis,exist}}_{pb,t,reg} \tag{85}$$

$$P^{\text{selfcon}}_{p,t,reg} = P^{\text{p2l}}_{p,t,reg} + P^{\text{dis}}_{pb,t,reg} + P^{\text{dis,exist}}_{pb,t,reg} \tag{86}$$

$$P^{\text{g2l}}_{p,t,reg}, P^{\text{p2g}}_{p,t,reg}, P^{\text{p2l}}_{p,t,reg} \geq 0 \tag{87}$$

where $P^{\text{selfcon}}_{p,t,reg}$ denotes the self-consumed PV generation. Note that four PV-battery types each associated with one of the four PV size categories are considered to reflect the different economic trade-offs (e.g. electricity tariffs) faced and the investments made by the investors of different sizes of PV.

Power Balance constraint of the system For the distribution system in each region, at each time step, the sum of the net electricity generation (i.e. generation minus consumption) must be equal to the electricity exchange with the transmission system P^{DA}, i.e.

$$\begin{aligned}&\sum_{g\in G}(P_{g,t,reg} + P^{\text{exist}}_{g,t,reg}) + \sum_{v\in V\setminus P}(P_{v,t,reg} + P^{\text{exist}}_{v,t,reg}) + \sum_{s\in S}(P^{\text{dis}}_{s,t,reg} + P^{\text{dis,exist}}_{s,t,reg} - P^{\text{ch}}_{s,t,reg} - P^{\text{ch,exist}}_{s,t,reg}) - P^{\text{L,sch,npv}}_{t,reg}\\ &+ \sum_{p\in P}(P^{\text{p2g}}_{p,t,reg} - P^{\text{g2l}}_{p,t,reg}) = P^{\text{DA}}_{t,reg}\end{aligned} \tag{88}$$

where the first line includes all devices and consumers except for consumers with PV or PVB systems which are included using their interaction with the grid in the second line. The exchange with the grid P^{DA} is positive when selling to and negative when purchasing from the transmission grid.

Market constraint As distribution transformers are rarely fully loaded in reality for security reasons, the power that is exchanged between the distribution and the transmission system considering the reserve provision is set to be limited by the transformer capacity, which is estimated by the regional peak demand $P^{\text{L,max}}_{reg}$ multiplied by a factor γ^{ex} that is greater than one, i.e.

$$P^{\text{DAs}}_{t,reg} + P^{\text{RMu}}_{t,reg} \leq \gamma^{\text{ex}} P^{\text{L,max}}_{reg} \tag{89}$$

$$P^{\text{DAb}}_{t,reg} + P^{\text{RMd}}_{t,reg} \leq \gamma^{\text{ex}} P^{\text{L,max}}_{reg} \tag{90}$$

$$P^{\text{DA}}_{t,reg} = P^{\text{DAs}}_{t,reg} - P^{\text{DAb}}_{t,reg} \tag{91}$$

$$P^{\text{RMu}}_{t,reg} = \sum_{g\in G}(RU_{g,t,reg} + RU^{\text{exist}}_{g,t,reg}) + \sum_{s\in S}(RU_{s,t,reg} + RU^{\text{exist}}_{s,t,reg}) + RU^{\text{L}}_{t,reg} \tag{92}$$

$$P^{\text{RMd}}_{t,reg} = \sum_{g\in G}(RD_{g,t,reg} + RD^{\text{exist}}_{g,t,reg}) + \sum_{s\in S}(RD_{s,t,reg} + RD^{\text{exist}}_{s,t,reg}) + RD^{\text{L}}_{t,reg} \tag{93}$$

where $P^{\text{RMu}}_{t,reg}$ and $P^{\text{RMd}}_{t,reg}$ are the total up- and down-reserve capacity bidding of the aggregator, $P^{\text{DAs}}_{t,reg}$ and $P^{\text{DAb}}_{t,reg}$ are the power sold to and purchased from the transmission grid. In addition, the reserve capacity is generally required to be provided for a certain period of time (e.g. one week):

$$P^{\text{RMu}}_{t,reg} = P^{\text{RMu}}_{t0,reg} \quad \text{for} \quad \forall t \in [t_0, t_0 + \delta_{res}] \tag{94}$$

$$P^{\text{RMd}}_{t,reg} = P^{\text{RMd}}_{t0,reg} \quad \text{for} \quad \forall t \in [t_0, t_0 + \delta_{res}] \tag{95}$$

where t_0 is the starting time point of each reserve bidding period and δ_{res} is the minimum time length of the reserve provision.

Policy constraint

Renewable target The annual renewable generations over all regions in Switzerland are required to exceed a certain value for the corresponding simulation year y, i.e. the renewable target β^{RES}_y. Mathematically,

$$\sum_t \sum_{reg \in REG} [\sum_{g \in G \cap RES} (P_{g,t,reg} + P^{\text{exist}}_{g,t,reg}) + \sum_{v \in V \cap RES} (P_{v,t,reg} + P^{\text{exist}}_{v,t,reg})] \geq \beta^{\text{RES}}_y \tag{96}$$

where $\mathbf{RES}$ represents the set of renewable generation units.

3.2.2 Formulation of optimization problem

The goal is to optimize the investment and operation decisions of distributed generation units and the demand response program, so as to minimize the total costs. The total costs are equal to the sum of the first-stage investment costs and the second-stage operating costs over the whole simulation period, where the latter comprise fixed operation costs C^{foc}, variable operation and maintenance costs C^{voc}, emission costs C^{em}, discomfort costs C^{dr} and additional cost adjustments seen by PV investors C^{pv} minus revenues from market participation R^{m}, investment subsidies R^{sub}, tax rebate for renewable operation costs $R^{\text{tax,op}}$ and tax rebate for renewable net investment costs $R^{\text{tax,inv}}$.

As we take the consumer's perspective for PV investment, the additional cost term C^{pv} is included to adjust the cost and profits seen by the consumers. It consists of two parts: 1) adjustment of the profits by injecting excess energy back to the grid. Instead of the wholesale price, the PV injection is reimbursed by the injection tariff provided by the corresponding distribution system operator (DSO); 2) adjustment of the savings from the self-consumed PV generations. The self-consumed portion of the PV generation is used to offset the retail tariff faced by the consumers, instead of the wholesale price.

As mentioned, due to computational restrictions, a limited number of days are selected to represent the variations in supply and demand over the year. Mathematically,

$$C^{\text{inv}}_{reg} = \sum_{i \in I} \gamma^{\text{ann}}_i c^{\text{inv}}_i x^{\text{inv}}_{i,reg} \tag{97}$$

$$C^{\text{foc}}_{reg} = \sum_{i} c^{\text{foc}}_i (x^{\text{inv}}_{i,reg} + x^{\text{exist}}_{i,reg}) \tag{98}$$

$$C^{\text{voc}}_{t,reg} = \sum_{i \in I} c^{\text{voc}}_i (P_{i,t,reg} + P^{\text{exist}}_{i,t,reg}) \tag{99}$$

$$C^{\text{em}}_{t,reg} = \sum_{i \in I} c^{\text{em}} \alpha^{\text{em}}_i (P_{i,t,reg} + P^{\text{exist}}_{i,t,reg}) \tag{100}$$

$$C^{\text{dr}}_{t,reg} = c^{\text{dr}} (r^{\text{L+,npv}}_{t,reg} + RD^{\text{L}}_{t,reg}) \tag{101}$$

$$C^{\text{pv}}_{t,reg} = \sum_{p \in P} [P^{\text{p2g}}_{p,t,reg} (pr^{\text{DA}}_{t,reg} + c^{\text{grid}}_{t,reg} - pr^{\text{injection}}_{t,reg}) + P^{\text{selfcon}}_{p,t,reg} pr^{\text{margin}}_{p,t,reg}] \tag{102}$$

$$R^{\text{m}}_{t,reg} = (pr^{\text{DA}}_{t,reg} + c^{\text{grid}}_{t,reg}) P^{\text{DA}}_{t,reg} + pr^{\text{RMu}}_{t,reg} P^{\text{RMu}}_{t,reg} + pr^{\text{RMd}}_{t,reg} P^{\text{RMd}}_{t,reg} \tag{103}$$

$$R^{\text{sub}}_{reg} = \sum_{i \in I} \gamma^{\text{ann}}_i r^{\text{sub}}_i x^{\text{inv}}_{i,reg} \tag{104}$$

$$R^{\text{tax,op}}_{reg} = \sum_{v \in V} r^{\text{tax,op}}_v [\gamma^{\text{d}} \sum_{t}^{T} c^{\text{voc}}_v (P_{v,t,reg} + P^{\text{exist}}_{v,t,reg}) + c^{\text{foc}}_v (x^{\text{inv}}_{v,reg} + x^{\text{exist}}_{v,reg})] \tag{105}$$

$$R^{\text{tax,inv}}_{reg} = \sum_{v \in V} r^{\text{tax,inv}}_v \gamma^{\text{ann}}_v x^{\text{inv}}_{v,reg} (c^{\text{inv}}_v - r^{\text{sub}}_v) \tag{106}$$

where c^{inv}, c^{foc}, c^{voc}, c^{em}, α^{em}_g, c^{dr}, r^{sub}, $r^{\text{tax,op}}$ and $r^{\text{tax,inv}}$ are constants and γ^{ann} is the annuity factor computed by $\frac{r}{1-1/(1+r)^l}$, where r is the weighted average cost of capital (WACC) and l is the amortization period of the candidate unit. The hour of all selected days is indicated by T and γ^{d} equals to the total number of days of the examined year N_d divided by the number of simulation days n_d. The day-ahead wholesale market price, the upward and the downward reserve market prices at time t for region reg are represented by $pr^{\text{DA}}_{t,reg}$, $pr^{\text{RMu}}_{t,reg}$ and $pr^{\text{RMd}}_{t,reg}$, respectively. $pr^{\text{injection}}_{t,reg}$ is the tariff set by each DSO to subsidize the PV injection back to the grid. $pr^{\text{margin}}_{p,t,reg}$ is the wholesale-to-retail margin used to represent the markups made to the wholesale electricity price so as to bring it to the retail electricity price. In turn, the self-consumed portion of the PV generation in the model is reimbursed at the consumer price level, which better reflects the consumers' savings and economic trade-offs. It is worth noting that we do not include self-consumption of generation units except PV and, instead, assume that their owners sell the electricity at the wholesale market. We do so, as we assume that larger investors install these units and not individual households.

Thus, the optimization problem can be formulated as

$$\begin{aligned} \min \quad & \sum_{reg \in REG} [C^{\text{inv}}_{reg} + C^{\text{foc}}_{reg} - R^{\text{sub}}_{reg} - R^{\text{tax,op}}_{reg} - R^{\text{tax,inv}}_{reg} + \gamma^{\text{d}} \sum_{t=1}^{T} (C^{\text{voc}}_{t,reg} + C^{\text{em}}_{t,reg} + C^{\text{dr}}_{t,reg} + C^{\text{pv}}_{t,reg} - R^{\text{m}}_{t,reg})] \\ \text{s.t.} \quad & \text{Constraints (3)-(106)} \end{aligned}$$

4 Representation of flexibility

This section provides a brief description of how different distributed energy resources in the DistIv module related to the need and supply of flexibility in the power system.

4.1 Flexibility requirement

The increasing penetration of variable generations in distribution system increases the need of flexibility provision, as a result of their uncertain and intermittent generation output. Although variable generation units such as PV could provide downward reserve through curtailments, challenges still exist for the implementation.

4.2 Flexibility provision

Potential flexibility providers in DistIv module include dispatchable generation units, demand response programs and storage units. While dispatchable generation units mainly provide downward flexibility, demand response programs and storage units could provide flexibility in both directions by shifting demand and generation between different time periods.

5 Description of interfaces

The most significant novelty of the Nexus-e platform is that it combines the core modules used in a sophisticated way with automated interfaces to pass all necessary information between modules as shown in Figure 3. The DistIv module is connected within the Investment loop of this framework with an input-output interface with the CentIv and an output interface that sends data to the General Equilibrium Module for Electricity (GemEl) module.

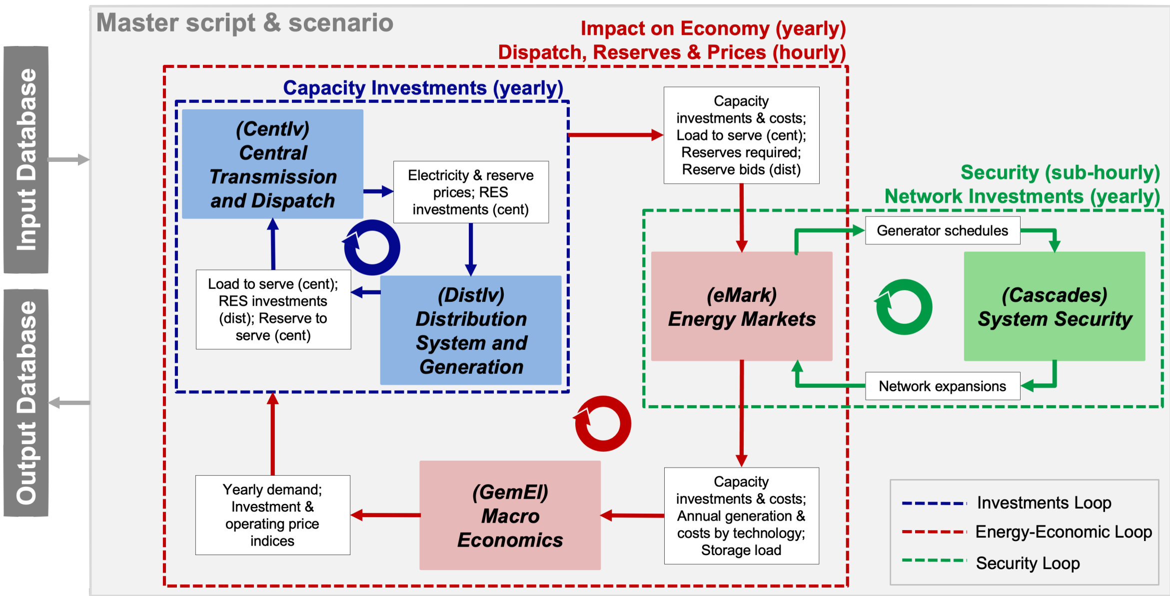

Figure 3: Illustration of the integration and interfacing of the various modules used in Nexus-e.

5.1 DistIv-CentIv interface

As part of the Investments Loop (see blue area in Fig. 3), DistIv is interfaced with CentIv in order to model a coordinated generation expansion planning (GEP) process at the transmission and distribution system levels. The DistIv-CentIv interface provides information on the operation and investments at the distribution level back to the centralized level. CentIv uses these data to adjust the demand and reserve requirements and re-evaluate the investments at the transmission level. The data transferred from DistIv to CentIv are summarized in Table 3.

Table 3: DistIv-CentIv module interface details.

Variable	**Resolution**	**Unit**	**Description**
Residual Demand	hourly*, nodal	MW	Residual demand (original demand minus distributed generation and DSM/BSS load shifting)
Residual Secondary Reserve Requirement	hourly*	MW	Residual hourly system secondary up/down reserve requirement
renewable energy source (RES) Production	annual	TWh	Total production from renewables in DistIv
Invested PV Capacity	annual, by unit type	MW	Annual PV investments during simulation year in DistIv
Distributed Generation	hourly*, nodal	MW	Generation from all units in the distribution system (existing and newly built)

* *uses an hourly resolution but simulates only every other day of the year to reduce the computational complexity*

The residual demand represents the remaining load that must be supplied by CentIv considering all distributed generation as well as DSM/BSS load shifting. Similarly, the residual reserve requirements need to be supplied by the centralized generators. The RES generation from DistIv is used if the scenario includes a renewable production requirement to calculate the remaining portion of this requirement that CentIv must supply. Finally, the PV capacity invested in by DistIv in this scenario-year is needed by CentIv to calculate the increased need for reserves to cover this added PV capacity. After each scenario-year simulation the invested distributed generation is appended to the input database and used by CentIv in the next scenario-year to account for expected injection from already existing distributed units.

5.2 CentIv-DistIv Interface

The CentIv-DistIv interface provides information on the operation and investments at the transmission system level. The data transferred from CentIv to DistIv are summarized in Table 4. These data enable DistIv to optimize the trade-off between making new investments at the distribution level and purchasing the electricity to supply the demand from the transmission system. Both CentIv and DistIv use an hourly resolution but simulate only every other day of the year to reduce the computational complexity[1]. We marked parameters that have an hourly resolution with an asterisk (*) to highlight this simplification. The CentIv and DistIv module reports provide more information regarding the implications of this time compression on the problem formulation.

[1] We understand that such a reduced time step will incur a loss of accuracy in the results. However, preliminary test indicated that the trade-off between loss of accuracy versus improved computation time was acceptable.

Table 4: CentIv-DistIv module interface detail.

Data	Resolution	Unit	Description
Original Demand	hourly*, nodal	MW	Original transmission system demand
Electricity Price	hourly*, nodal	CHF/MWh	Dual variable of energy balance equation
Secondary Reserve Requirement	hourly*	MW	System secondary up/down reserve requirement
Secondary Reserve Price	hourly*	CHF/MWh	Dual variable of secondary reserve requirement equation
Total Net Generation	annual	MWh	Total net generation (generation - pump consumption) in CentIv
Investment Costs	annual	CHF	Investment and Fixed operation and maintenance (OM) costs of newly built units in CentIv
RES Production	annual	TWh	Total production from non-hydro RES (biomass, wind, PV) in CentIv
Original RES Target	annual	TWh	Target for production from non-hydro RES (biomass, wind, PV)

* *uses an hourly resolution but simulates only every other day of the year to reduce the computational complexity*

DistIv separates the hourly demand for each distribution region and optimizes how these regional demands are supplied. New investments in distributed units could supply these demands or alternatively they can be supplied by purchasing from the centralized level at the electricity price. Simultaneously, DistIv uses the reserve requirement and centralized reserve price to enable distribution units to also supply reserves. As part of the optimization, DistIv also uses the annual net generation and investment costs from CentIv as a cost factor that is incurred in addition to the wholesale electricity price when demand is supplied by purchasing from the centralized level. Finally, the RES production and target from CentIv are used by DistIv when the scenario includes a requirement for renewable investments. In this case, the desired RES target must be met by the combination of RES generation in CentIv and DistIv (i.e. DistIv needs to at least fulfill the remaining target).

5.3 DistIv-GemEl interface

The DistIv-GemEl interface passes cost information for all generators, those newly built as well as those already existing, on the distribution system levels. This information is mapped to the technology types in GemEl and used to recalibrate the module to reflect the new generation mix and costs. Table 5 shows details of the data transferred through the DistIv-GemEl interfaces.

Table 5: DistIv-GemEl module interface details.

Variable	Resolution	Unit	Description
Investment cost	annual, by unit type	mill CHF	Investment cost per technology type
Fixed OM cost	annual, by unit type	mill CHF	Fixed OM cost per technology type

6 Demonstration of results

6.1 Input data

Table 6 summarizes the parameters used in DistIv based on the data in [14] (except for batteries). All values are expressed in Euros with an exchange rate of 1.1 CHF to 1 Euros. Note that the CO2 levy refund for gas-fired CHP plants are not considered.

Table 6: Parameters for candidate units

Type	Size	Investment cost (EUR/kW)	Variable operation cost (cent/kWh)	Fixed operation cost (EUR/kW/year)	Fuel cost (cent/kWh)	Emissions (eq. g/kWh)	Lifetime (years)	Amortization period (years)
PV	0-10 kWp	2'902	2.73	0	0	0	30	10
PV	10-30 kWp	2'295	2.73	0	0	0	30	10
PV	30-100 kWp	1'570	2.73	0	0	0	30	10
PV	>100 kWp	1'182	1.82	0	0	0	30	10
Biomass wood	50 kWe	6'033	0	675	19.00	35	10	10
Biomass manure	25 kWe	32'909	0	968	8.64	0	15	15
CHP	10 kWe	4'127	3.50	0	7.59	611	20	20
Grid-connected battery	100 kWh	638	0	2.5% of investment cost	0	0	20	20
PV-battery	13.5 kWh	1'156	0	2.5% of investment cost	0	0	15	15

Four categories of PV units are considered in DistIv, i.e. 0-10 kWp, 10-30kWp, 30-100kWp and >100kW. While 6 kWp and 100 kWp are selected as the reference size for the first and the fourth category, the average cost and subsidy information of the maximum and minimum size of the corresponding category are used for the second and third category. PV investments benefit from investment subsidies valid until 2030 based on Bundesamt für Energie (BFE) regulations, the investment subsidy assumed for 2020 is based on the level for commissioning time from 2020.04.01 on while in 2030 the subsidy is assumed to be decreased to 80% of the 2020 level. Subsidies for units such as biomass are not considered in this work. Furthermore, a tax rebate of 7.7% of the operation costs and 20% of the net investment costs (excluding investment subsidy) are considered for all years until 2050, while the investment cost tax rebate are not applied to investments in Luzern and Graubünden due to regional regulations. A linear degradation rate of 0.5% per year is assumed for all PV panels, i.e. each year the PV panel generates 0.5% of the rated output less than the year before. Irradiation data for PV units are from MeteoSwiss [15] while PV potentials in Switzerland shown in Fig.4 and Fig.5, which are based on the Sonnendach data assuming the area required for 1 kWp of PV is 6 square-meters. Not all cantons are shown in Fig. 4 as PV potentials of cantons without transmission nodes are aggregated into the nearby cantons.

Annual yield for biomass wood, biomass manure and CHP units are assumed to be 4689 kWh/kWe, 6800 kWh/kWe and 2453 kWh/kWe [14], respectively. All capacity factors are assumed to be unchanged for future years. Cost assumptions of PV units and storage units for future years, which are presented in percentage of the base year 2018, are summarized in Table 7. Investment and operational costs for other units are assumed to be unchanged.

In our model, the consumer price consists of three parts: (i) wholesale electricity price (signal from CentIv), (ii) the grid tariff (including both network tariff and Abgaben), and (iii) the wholesale-to-retail price margin. As mentioned, the price margin is only applied to the self-consumed portion of the PV generation to offset the retail tariff faced by the consumers. The price of electricity that the aggregator

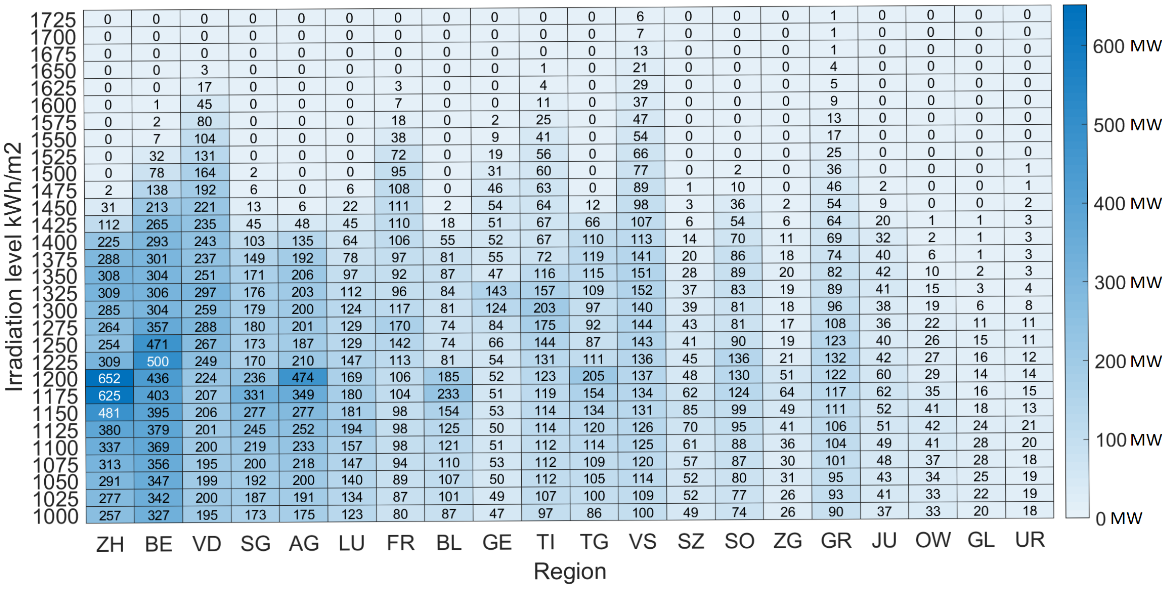

Figure 4: PV investment potential for different regions in MW.

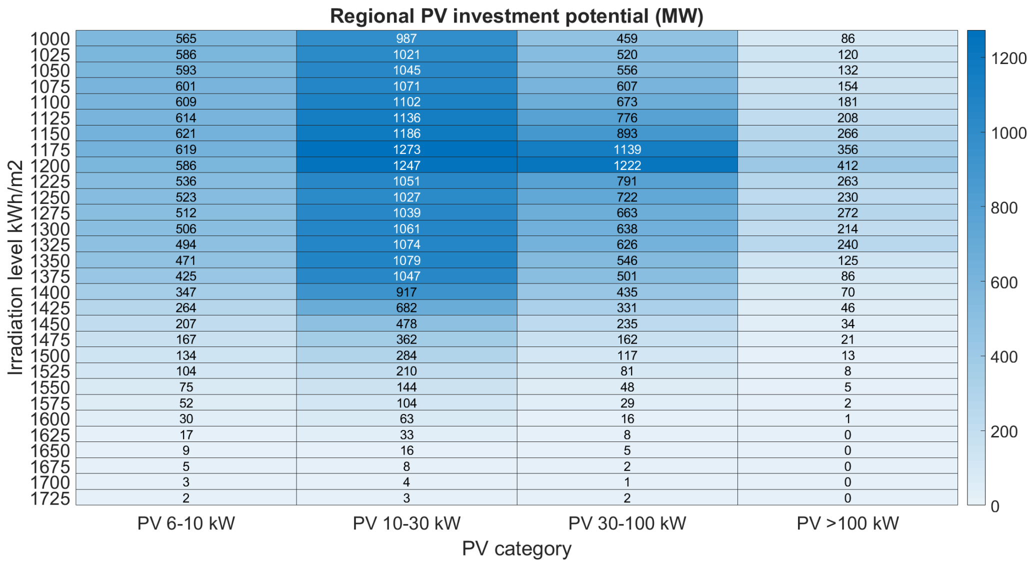

Figure 5: PV investment potential for different categories in MW.

Category	2018	2020	2030	2040	2050
0-10 kWp PV	100%	86%	71%	61%	57%
10-30 kWp PV	100%	87%	71%	57%	44%
30-100 kWp PV	100%	84%	69%	57%	48%
>100 kWp PV	100%	81%	66%	57%	52%
Grid-connected battery	100%	100%	72%	53%	39%
PV battery	100%	100%	72%	53%	39%

(a) Investment costs

Category	2018	2020	2030	2040	2050
0-10 kWp PV	100%	95%	78%	68%	64%
10-30 kWp PV	100%	95%	78%	68%	64%
30-100 kWp PV	100%	95%	78%	67%	64%
>100 kWp PV	100%	95%	78%	67%	64%
Grid-connected battery	100%	100%	72%	53%	39%
PV battery	100%	100%	72%	53%	39%

(b) Operational costs

Table 7: Assumptions for future investment and operational costs.

purchases and sells from and to the transmission grid only comprise the first two parts, i.e. (i) and (ii). While the price margin and grid tariff are kept constant over the years, the consumer price is expected to vary over future years. This possible variation is reflected by the changes of the electricity price signal from CentIv, i.e. the total retail electricity tariff seen by the consumers varies from year to year (in general it increases due to the increase of CO2 prices etc.). Details of the grid tariff and the wholesale-to-retail price margin are described in the following paragraphs.

The grid tariffs are different for different categories of users (H1-H8, C1-C7, i.e. 15 categories based on the regional grid tariff data provided by ElCom [16]), we calculated the weighted average grid tariff for each region by analyzing proportions of different categories in each region as follows:

- Split the total electricity consumption between households, industry, transportation and service based on [17];
- Further split households electricity consumption into H1-H8 based on the information about the number of rooms each household has provided by "Bundesamt für Statistik (BFS)";
- Further split consumption from industry and service areas based on the information about the number of employees they have provided by "Statistik der Unternehmensdemografie".

For the wholesale-to-retail price margin, instead of using one fixed number for all regions and all units, the model uses the difference between the 2018 tariff data for each canton from Elcom and the 2018 wholesale price simulated by the model to calculate it. As tariffs are different for different consumer categories (in total 15), different PV unit groups are assigned to different tariff categories based on the annual consumption information for each tariff category. To be more specific, consumption categories H1-H2, H4-H5, H8 and C1 are assigned to 0-10 kWp PV, consumption categories H6-H7 and C2 are assigned to 10-30 kWp PV, consumption category C3 is assigned to 30-100 kWp PV, and consumption categories C4-C7 are assigned to PV unit greater than 100 kWp.

The grid tariff, the injection tariff [18] and the detailed price margins applied for each PV category are listed in Appendix A, Appendix B and Appendix C, respectively.

The dispatchable generation unit has a ramp rate limit of 25% of its maximum capacity per hour. The PV battery storage unit and the grid-connected battery storage unit are modeled based on Tesla Powerwall 2 and Powerpack [19]. The total cost of installing Tesla Powerwall 2 is calculated assuming that the battery pack costs available on [19] account for 46% of the total investment costs [20]. The investment cost of Powerpack is based on [21] as no cost information is available on Tesla's official website. Technical parameters of the candidate battery units are listed in Table 8.

Table 8: Technical parameters for candidate storage units.

Type	Capacity (kWh)	Maximum charging discharging power (kW)	Initial storage level (kWh)	Hourly self-discharging rate (%)	Lifetime (years)
PV-battery	13.5	5	0	0	15
Grid-connected battery	100	50	0	0.1	20

It is assumed that the total maximum power that can be shifted per hour in Switzerland is limited to 0.7 GW, 0.9 GW, 1 GW and 1 GW, and the total energy shifted (including both downward and upward shifting) per day is limited to 2× 2.25 GWh, 2×2.75 GWh, 2×3 GWh and 2×3 GWh for years 2020, 2030, 2040 and 2050, respectively. The total shifting potential of demand is split between demand of consumers with and without PV units based on the ratio of their annual demand. The annual electricity consumption of PV investors is assumed to be 1 MWh per 1.1 kWp of PV investment and its demand profile is assumed to have the same pattern as the system demand. Demand response cost c^{dr} is set to 15 EUR/MWh. This number is distributed to different regions based on their annual demand levels. Parameter γ^{ex} is equal to 1.2 and the weighted average cost of capital for all technologies are assumed to be 5%.

6.2 Results

The section provides the results of the DistIv module for years 2020 to 2050 under the Baseline scenario. The demonstration results in this section provide a highlight of the capabilities and insights DistIv provides. These results are only for illustrative purposes and are not meant to represent the final results of the Nexus-e simulation framework for any particular scenario.

6.2.1 Investment results

The invested capacities of all technologies for the years 2020, 2030, 2040 and 2050 are listed in Table 9. It can be observed that only PV units and PV-batteries are invested in this case. As shown in the table, PV-batteries start to be invested in year 2040 and then experience a dramatic increase between 2040 and 2050. This is because the PV-battery installation is mainly driven by the investment costs and how much it can contribute to the savings of the PV investor by increasing the self-consumption rate of the PV generations. As the cost is reduced while the electricity tariff is increasing over the years, both contribute to higher profitability of PV-battery investments in future years. It is worth mentioning that although shown as one aggregated number the PV-battery investment is actually optimized on a cantonal level for each PV system size (<10kW; 10-30kW; 30-100kW; >100kW) and each irradiation level. In this way, the module can better optimize the PV-battery investment in terms of profitability from a end-consumer's perspective. PV investments shift towards smaller size categories (especially the second and the third categories) from bigger size categories from year 2020 to year 2050. This is mainly related to the fact that the biggest PV category reaches the investment potential limit already in early years and the second and the third PV categories are expected to experience a greater cost reduction until year 2050. Furthermore, there is little PV investment between year 2030 and year 2040, which is a result of the expiration of the investment subsidies by the end of 2030. However, as the cost reduction until year 2050 is large enough to cover the loss due to the expiration of the subsidy, small PV units become profitable in more rooftop areas and a significant amount of PV installations are seen in year 2050. Note that as only financial factors are considered in the objective function, results shown describe what is optimal to be invested from the economic perspective. Note that financial parameters such as weighted average cost of capital and payback periods are simplified as a constant value for all PV categories. More realistic would be to use different distributions of these parameters for each PV category, but this requires additional input data and increases the implementation overhead.

Table 9: Accumulated investments of different technologies in GW or GWh.

Category	Year 2020	Year 2030	Year 2040	Year 2050
PV 0-10kWp	0	0	0	0.04
PV 10-30kWp	0	0.002	0.938	12.255
PV 30-100kWp	1.173	7.596	8.018	12.804
PV >100kWp	2.267	3.543	3.543	3.543
Biomass wood	0	0	0	0
Biomass manure	0	0	0	0
CHP	0	0	0	0
Grid-connected battery	0	0	0	0
PV-battery	0	0	2.377	23.390

Figure 6 shows the spatial distribution of the installed PV capacity over the years. It can be seen that in early years it is optimal to invest PV mainly in regions with relatively higher irradiation levels (e.g. Ticino, Valais, Fribourg etc.), but thanks to the decreasing investment and operating costs of PV units and the increasing electricity tariffs, PV investments are becoming profitable in all regions starting from 2030. However, there is still a significant amount of PV potential left by the end of 2050. This is on one hand due to the limited transmission capacity of each region, i.e. PV injections back to the grid during high PV generation hours are capped by the regional transmission capacity and extra PV generations that can neither be consumed nor be injected to the grid need to be curtailed; on the other hand, due to the relatively high investment costs, even considering the cost reduction until 2050, smaller size PV units are only profitable to be invested in regions with higher annual irradiation levels and the residual potentials correspond to the smaller size rooftops in regions with lower irradiation levels. This can be verified by the results shown in Fig. 7.

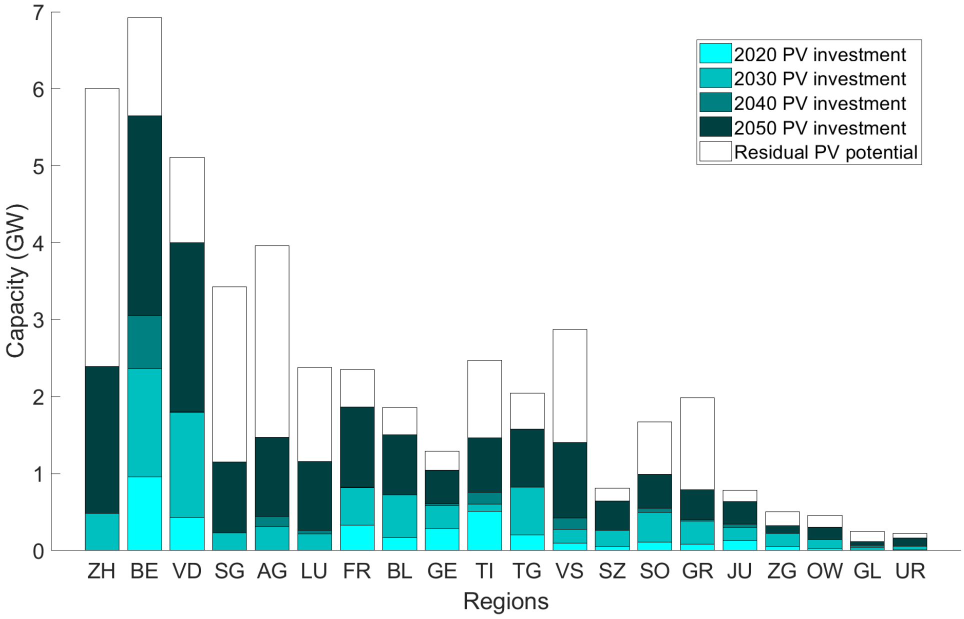

Figure 6: PV Investment per region

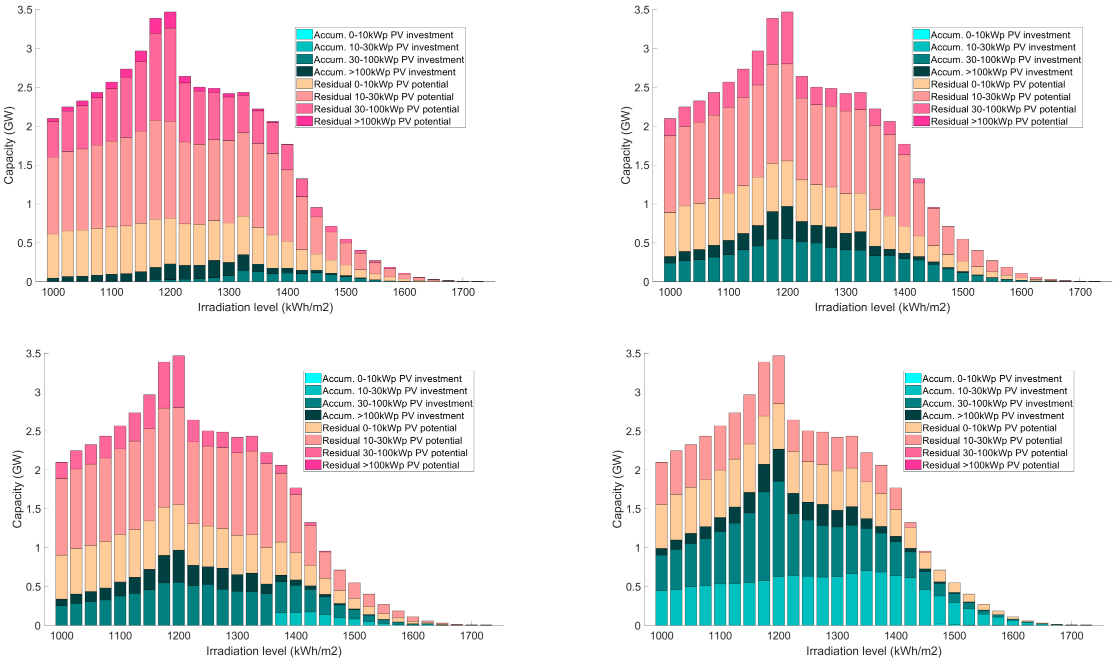

Figure 7: PV investments for the years 2020, 2030, 2040 and 2050.

6.2.2 Dispatch Results

Figure 8 shows the electricity generation of all technologies for the years 2020, 2030, 2040 and 2050, which is consistent with the investment results in Table 9. An increasing amount of total Swiss load is covered by the distribution system due to the expansion of PV capacities. Figure 9 shows the monthly electricity generation of each year.

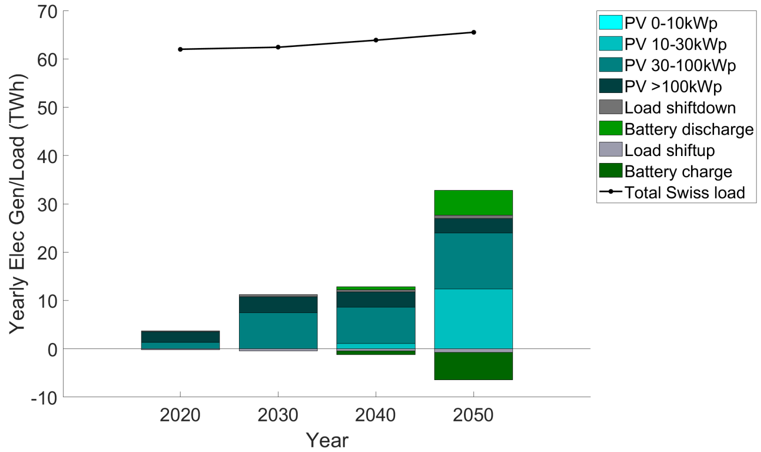

Figure 8: Electricity generation between 2020 and 2050.

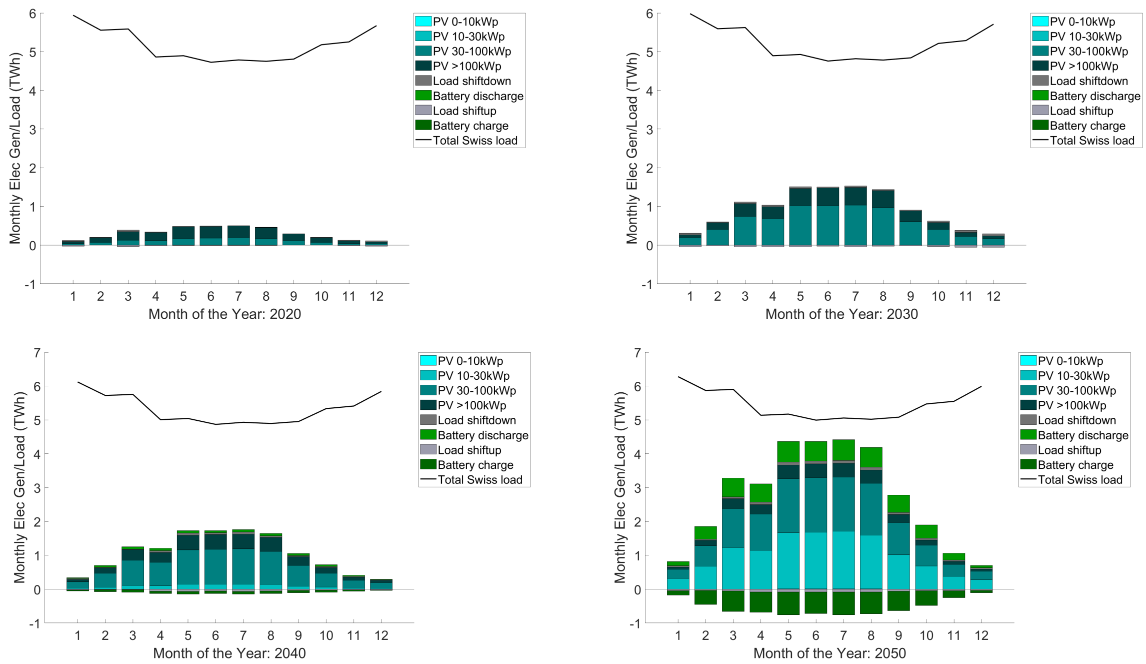

Figure 9: Monthly electricity generation for the years 2020, 2030, 2040 and 2050.

Figure 10 shows the generation and load dispatch of the PV system of an example winter week and an example summer week for 2020 and Fig. 11 shows the results for 2050 when there are PV-battery installations. In general, demand shifts down and PV-battery discharges at low PV generation periods, and demand shifts up and PV-battery charges at high PV generation periods. However, their behaviors are also affected by the variations of electricity prices.

To better illustrate the dispatch of different components of the PV system, i.e. the PV unit, the PV-battery unit and the elastic PV system demand, and to analyze how PV-batteries and demand response contribute to improving the PV self-consumption rate. Figure 12 shows the dispatch of the demand response and PV-batteries as a reaction to the electricity prices of an example winter week and an example summer week for 2050. It can be seen that generally demand shifts from low PV generation and high price periods to high PV generation and lower price periods to reduce the total consumption costs. The PV-battery behaves similarly to the demand response, but it has the ability to store energy and therefore has higher flexibility. The PV self-consumption rate can be increased to more than 60% with the installation of PV batteries. When there is a generation surplus of the PV system (i.e. PV generation higher than the PV system demand), PV-batteries absorb the excess energy through charging and then discharge during hours without PV generations to supply the demand. In this way, the PV investor reduces the electricity bill by increasing the self-consumption rate of local generations. This behavior can be observed especially during the summer week when the PV generation during lunch time in general is much higher than the demand levels.

As described in the mathematical formulation, the self-consumed energy consists of the energy directly from the PV generation and the energy discharged by the PV-battery. In general as the injection tariff is lower than the consumer electricity tariff, the PV generation is firstly used to cover the demand so as to save the electricity cost. However, when the low electricity price and the high PV generation occur at the same time (e.g. the first day of the example winter and summer weeks), which is a highly possible scenario in the future, the PV-battery charges almost all the PV generations and the self-consumed energy is lower than both PV generation and the demand. In this way, the PV system is able to benefit from electricity price variations between different hours.

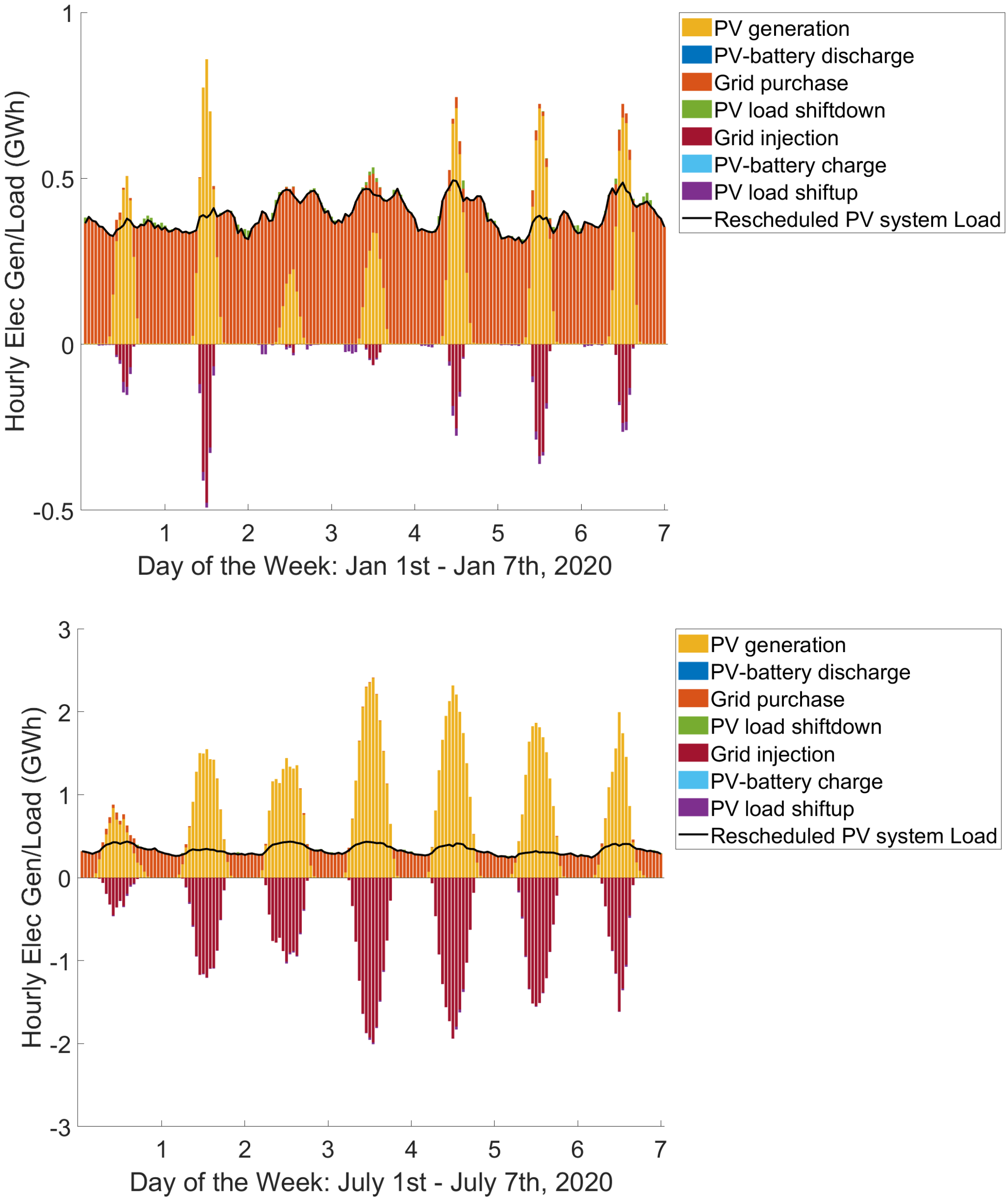

Figure 10: Hourly PV system dispatch for one summer week and one winter week of year 2020

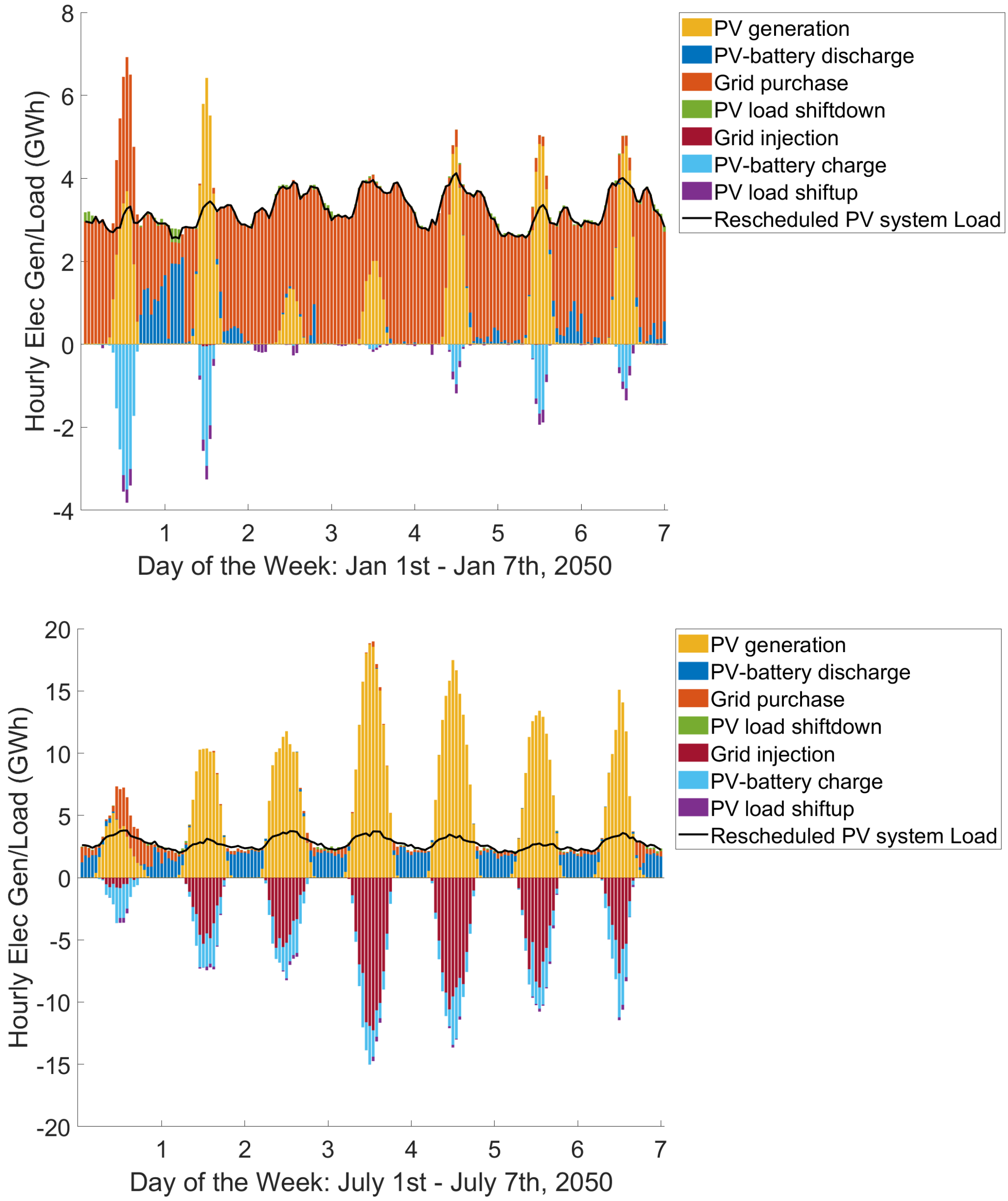

Figure 11: Hourly PV system dispatch for one summer week and one winter week of year 2050

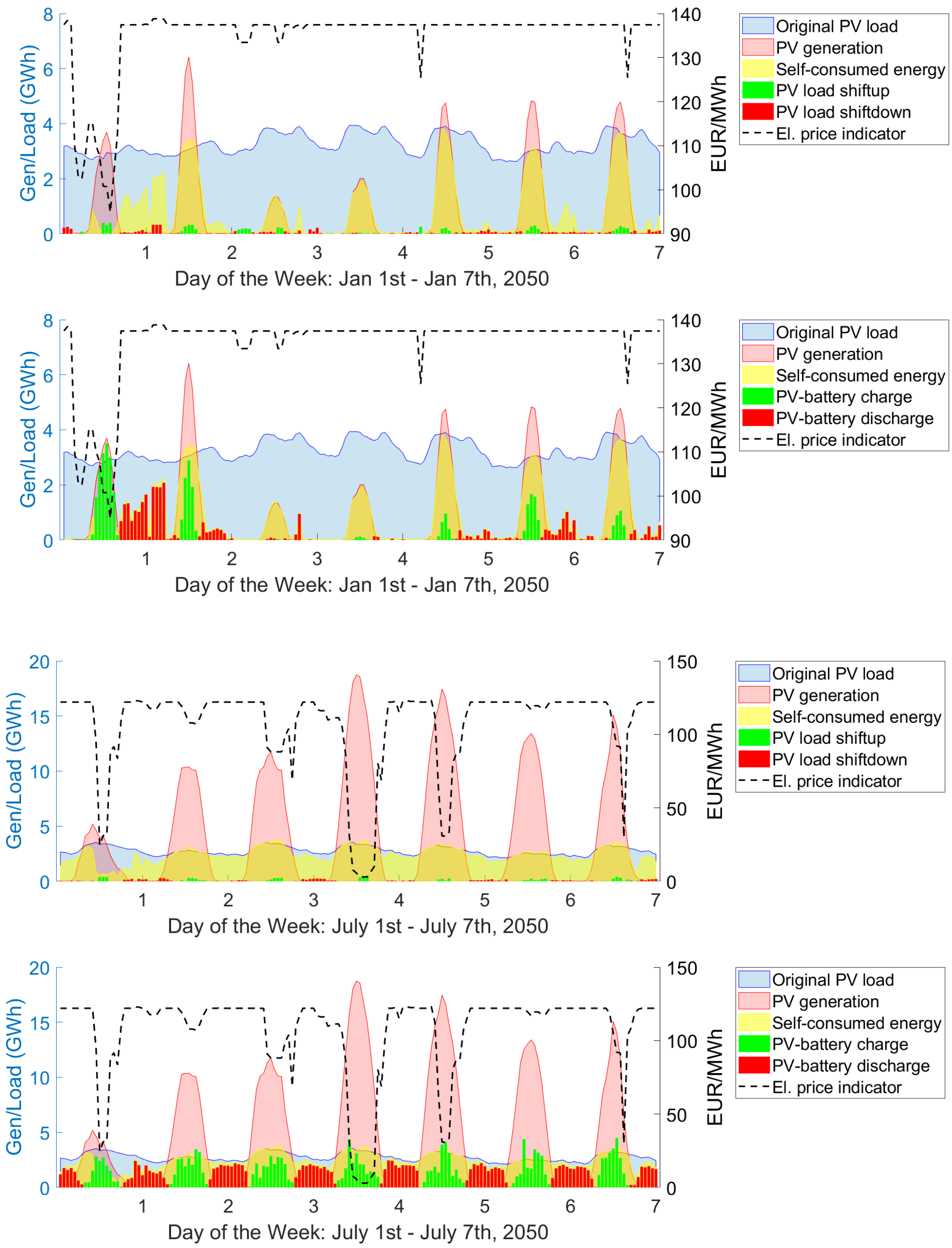

Figure 12: Hourly PV-controlled DR and PV-battery dispatch for one summer week and one winter week of year 2050

7 Publications

The following list describes publications related to the Nexus-e platform and the DistIv module:

- A paper presented at the 2017 IEEE Innovative Smart Grid Technologies-Asia Conference details a new method to derive optimal day-ahead trading strategies for an aggregator of a decentralized energy resources' mix, who participates in a multi-market environment, including a day-ahead, an intraday and a balancing market [22].
- A paper presented at the 2018 Power Systems Computation Conference (PSCC) that presents a stochastic bi-level model to derive optimal offering strategies for an aggregated PV power plant, who participates as a price-maker in both day-ahead and intraday markets, and a deviator in the balancing market [23].
- A paper presented at the 2019 PowerTech Conference that proposed a generation expansion planning strategy for distribution systems to derive the optimal generation mix considering decentralized storage units, variable generation units, dispatchable generation units and demand response [24].
- A paper published on Electric Power Systems Research journal that presents a two-stage distributionally robust model to derive optimal bidding strategies for an aggregated wind power plant (WPP), that participates as a price-maker in the day-ahead market, and a deviator in the balancing market [25].
- A paper presented at the 2019 16th International Conference on the European Energy Market that proposed a generation expansion planning strategy to derive the optimal mix of distributed generations in a market environment [26].
- A paper presented at the 2019 IEEE Innovative Smart Grid Technologies-Asia (ISGT Asia) Conference that presented a generation expansion planning strategy to derive the optimal generation mix for distribution systems using distributionally robust optimization [27].

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Appendices

A Grid tariff

Table 10: Calculated weighted average grid tariff in cent/kWh.

Index	Canton	Abgaben	Netznutzung	Total grid tariff
1	ZH	0.15	5.50	5.65
2	BE	0.54	8.08	8.62
3	LU	0.59	6.70	7.30
4	UR	0.84	8.81	9.65
5	SZ	0.63	7.15	7.77
6	OW	1.18	7.54	8.72
7	NW	1.00	6.36	7.35
8	GL	0.30	8.69	8.99
9	ZG	0.49	5.96	6.45
10	FR	0.00	5.96	5.96
11	SO	0.46	6.66	7.12
12	BS	5.72	6.39	12.10
13	BL	0.53	5.53	6.06
14	SH	0.00	7.28	7.28
15	AR	0.00	6.28	6.28
16	AI	0.00	6.10	6.10
17	SG	0.39	6.18	6.57
18	GR	1.05	8.94	9.98
19	AG	0.41	5.79	6.20
20	TG	0.32	7.07	7.39
21	TI	1.91	7.13	9.04
22	VD	0.90	7.40	8.30
23	VS	0.68	6.36	7.04
24	NE	1.53	6.17	7.70
25	GE	0.88	5.96	6.85
26	JU	0.51	8.25	8.76

B PV injection tariff

Table 11: PV injection tariff in cent/kWh.

Index	Canton	Injection tariff
1	ZH	5.03
2	BE	9.25
3	LU	8.18
4	UR	8.97
5	SZ	9.33
6	OW	10.00
7	NW	6.49
8	GL	6.82
9	ZG	11.01
10	FR	8.45
11	SO	8.18
12	BS	11.82
13	BL	5.91
14	SH	5.91
15	AR	4.32
16	AI	9.09
17	SG	5.45
18	GR	9.09
19	AG	5.45
20	TG	10.00
21	TI	10.00
22	VD	7.42
23	VS	5.73
24	NE	8.45
25	GE	8.97
26	JU	9.25

C Wholesale-to-retail price margin

Table 12: Wholesale-to-retail price margin in cent/kWh.

Index	Canton	0-10 kWp PV	10-30 kWp PV	30-100 kWp PV	>100 kWp PV
1	ZH	17.08	14.30	14.29	11.76
2	BE	23.53	19.89	19.88	17.01
3	LU	21.89	17.89	17.05	13.85
4	UR	23.76	18.61	16.72	14.51
5	SZ	20.28	17.06	16.74	13.49
6	OW	22.43	18.51	17.73	14.50
7	NW	19.86	16.73	16.13	14.66
8	GL	21.61	17.71	19.46	14.37
9	ZG	18.72	15.25	15.26	12.16
10	FR	20.92	17.09	19.12	15.35
11	SO	22.20	18.59	18.81	15.63
12	BS	27.51	24.54	25.64	21.63
13	BL	21.85	18.34	18.81	13.91
14	SH	20.78	16.97	16.65	13.06
15	AR	17.66	14.53	13.50	12.24
16	AI	17.80	14.50	14.07	11.50
17	SG	19.10	15.82	15.18	12.70
18	GR	21.38	18.44	19.55	18.06
19	AG	19.45	15.29	16.21	12.42
20	TG	19.12	16.28	16.54	13.72
21	TI	19.45	17.14	19.22	15.60
22	VD	21.34	18.09	17.70	16.97
23	VS	17.96	15.38	15.18	13.80
24	NE	21.79	17.99	18.80	15.59
25	GE	20.00	18.31	19.52	16.07
26	JU	27.17	21.40	21.81	17.17