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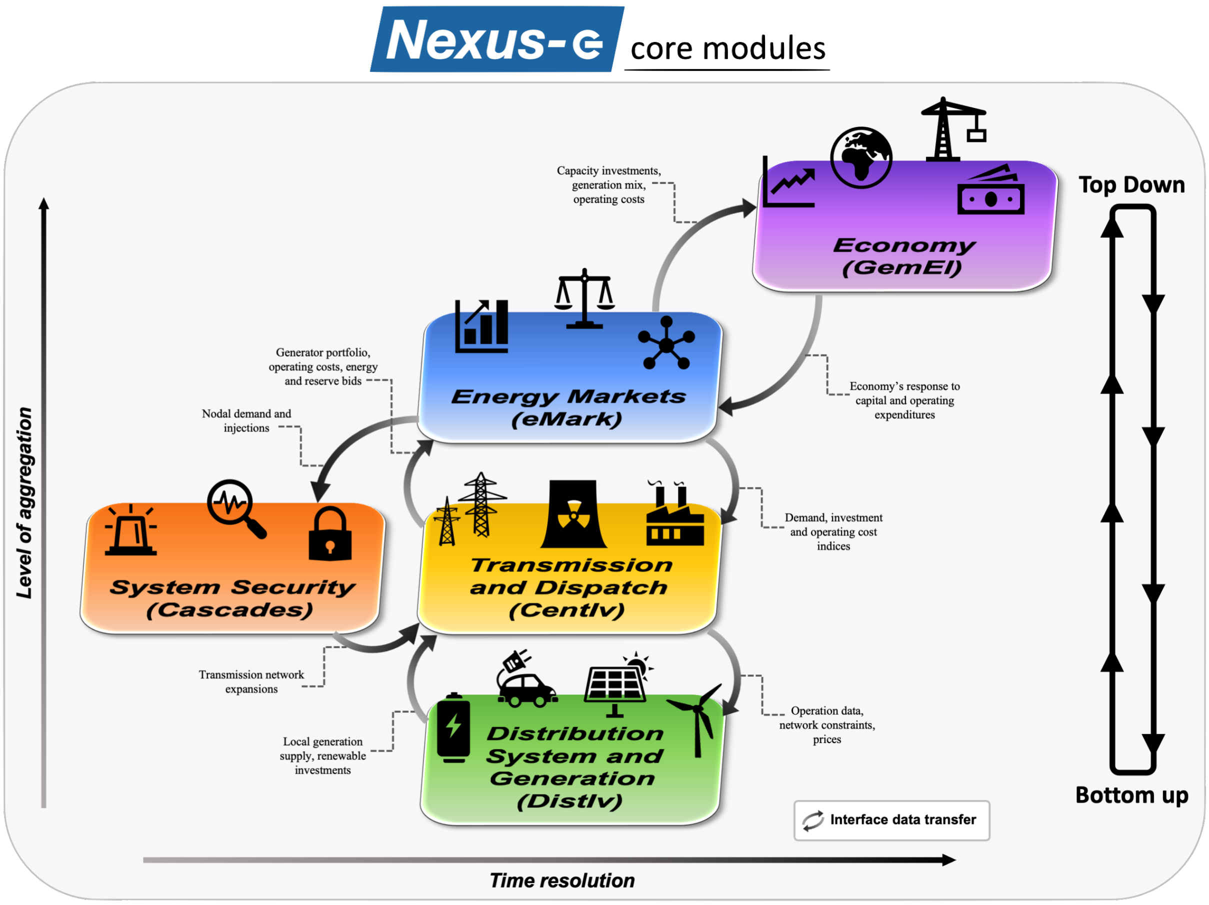
Final report

Nexus-e: Integrated Energy Systems Modeling Platform

Input Data and System Setup



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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 provides the description and documentation for the input data used by all modules.

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 enthält die Beschreibung und Dokumentation für die von allen Modulen verwendeten Eingabedaten.

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 fournit la description et la documentation des données d'entrée utilisées par tous les modules.

Contents

Abbreviations

AT	Austria
BFE	Bundesamt für Energie
BFS	Bundesamt für Statistik
Cascades	Network Security and Expansion Module
CC	combined cycle
CentIv	Centralized Investments Module
CES	constant-elasticity of substitution
CGE	computable general equilibrium
CHP	combined heat and power
CO_2	carbon dioxide
DE	Germany
DistIv	Distributed Investments Module
DSM	demand-side management
DSO	distribution system operator
eMark	Electricity Market Module
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FB	flow-based
FOM	fixed operation and maintenance
FR	France
GDP	gross domestic product
GemEl	General Equilibrium Module for Electricity
GEP	generation expansion planning
HBS	household budget survey
IOT-Energy	differentiated input–output table for the energy sector
IT	Italy
MW	megawatt
NTC	net transfer capacity
PV	photovoltaic
RES	renewable energy source
RoR	run of river
SC	simple cycle
TYNDP	ten-year network development plan
UFLS	under-frequency load shedding
UVLS	under-voltage load shedding
VOM	variable operation and maintenance

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1 Network data

The Nexus-e platform represents aspects of both the transmission and distribution levels of the Swiss and European networks. In this section, data and their sources are detailed that are used to model the transmission grid of Switzerland and its neighboring countries (Section 1.1) as well as to model the Swiss distribution grid (Section 1.2).

1.1 Transmission grid

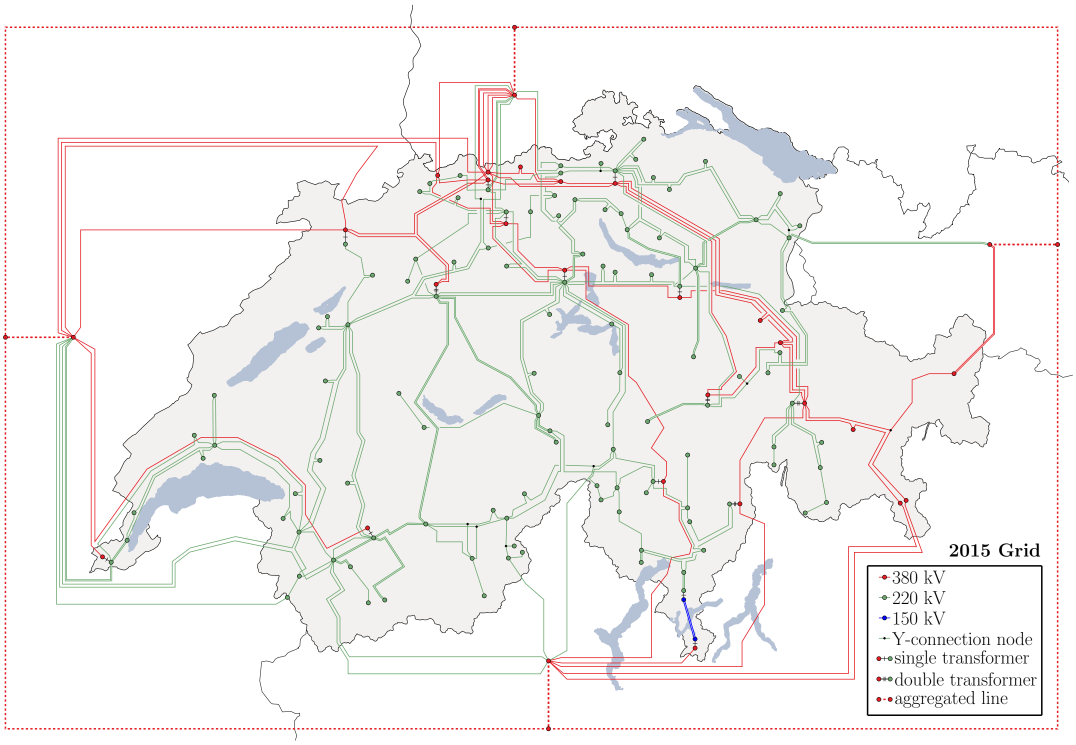
The Nexus-e framework includes a detailed representation of the Swiss transmission grid and an aggregated representation of the transmisson grid of the four neighboring countries - Germany (DE), France (FR), Italy (IT), and Austria (AT), with data from Swissgrid [1] and the European Network of Transmission System Operators for Electricity (ENTSO-E) [2, 3]. Figure 1 shows the 2015 transmission grid (used in the calibration) and the 2025 transmission grid (includes planned line upgrades until 2025). We use the latter to simulate the scenario-years 2030, 2040, and 2050, while with only appropriate upgrades for 2020. In total, the 2025 model comprises 173 nodes, 281 lines and 25 transformers.

To model the grid connection with the neighboring countries, we aggregate the fully detailed ENTSO-E network data using a sophisticated network reduction method, which we developed for this project [4]. More details on the network reduction process, which is done as part of the calibration of Centralized Investments Module (CentIv) and Electricity Market Module (eMark), can be found in the "Validation and Calibration of Modules" report. 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 (2015 data [5] and 2025 data [1, 6]). However, 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. Table 1 includes the final branch reactances of all aggregate non-Swiss lines (see Figure 1) used in the simulations.

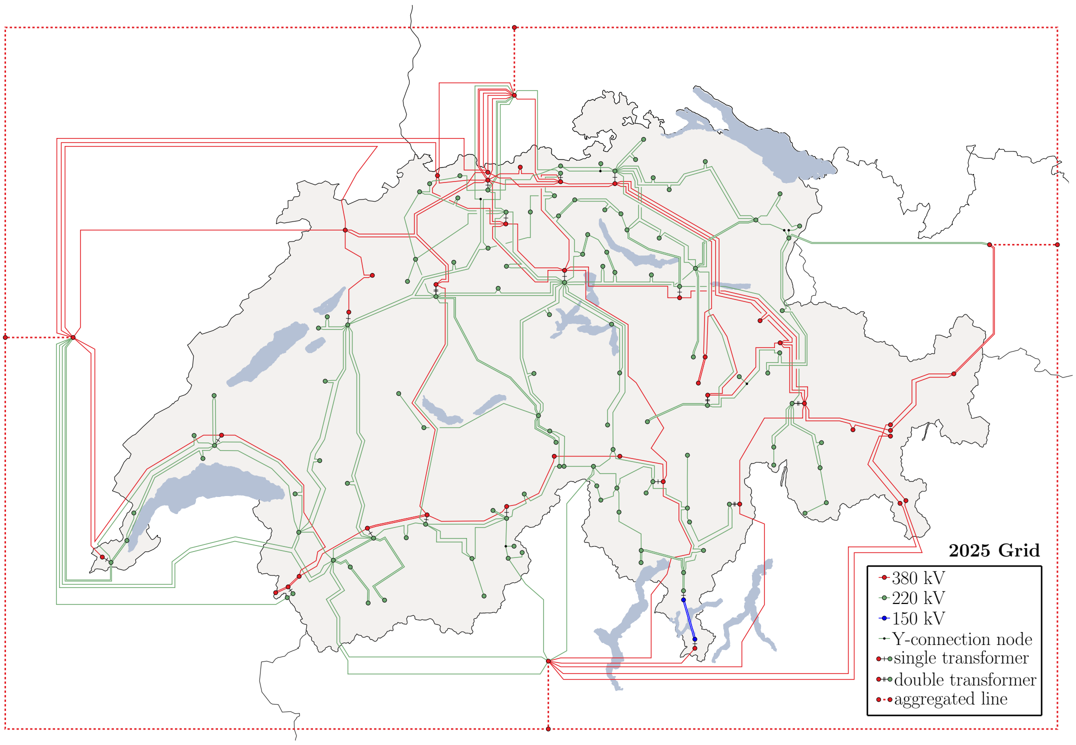
Table 1: Final branch reactances (x) of the aggregated lines used in all years in per unit (pu). Apparent power base is 100 MVA.

TO	FROM	x [pu]
CH	AT	0.006753316974
CH	DE	0.000197498974
CH	FR	0.005065744177
CH	IT	0.000022989669
AT	DE	0.000026352146
AT	IT	0.181678820844
DE	FR	0.002596863881
FR	IT	0.006605683155

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



(a) 2015 transmission grid



(b) 2025 transmission grid

Figure 1: Modeled transmission grids

modified limits to reflect the market-based transfer capacities. We gathered the data for these limits on market-based transfer capacities from Swissgrid [7] and the ENTSO-E Transparency Platform for the forecasted transmission allocation of day-ahead transfer capacities [8]. Table 2 lists the NTC values utilized in all historical simulations. Note that the large values for the DE-FR and DE-AT connections are because these borders are already FB coupled. We also increase these transfer limits between 2020 and 2050 based on the ten-year network development plan (TYNDP) available from ENTSO-E [2]. Table 3 lists all modeled NTC changes and the years these changes occur (i.e., replace the original NTC values from Table 2).

Table 2: NTC trade limitations between market zones in megawatt (MW) as modeled for all historical simulations (i.e., prior to 2020).

		FROM				
		CH	**AT**	**DE**	**FR**	**IT**
TO	**CH**	—	533	800	3000	1910
	AT	1200	—	9657	—	200
	DE	4000	9657	—	8074	—
	FR	1200	—	8074	—	2400
	IT	4240	1200	—	2400	—

Table 3: Changes to NTC trade limitations between market zones in MW as modeled for all 2020-2050 simulations. These NTC replace those previous listed and are based on already planned cross border transmission expansions [3] and assumed longer-term enhancements.

TO	**FROM**	**NTC trade limits [MW]**	**Years**
DE	CH	4000	2040-2050
CH	FR	3000	2040-2050
DE	FR	9236	2030-2050
FR	DE	9236	2030-2050
DE	AT	13395	2020
DE	AT	14895	2030-2050
AT	DE	13395	2020
AT	DE	14895	2030-2050
FR	IT	3801	2020-2050
IT	FR	3801	2020-2050
IT	AT	295	2020
IT	AT	1218	2030-2050
AT	IT	295	2020
AT	IT	1218	2030-2050

The Network Security and Expansion Module (Cascades) uses module specific data for the the under-frequency load shedding (UFLS) scheme, the under-voltage load shedding (UVLS) procedure, and to generate the sets of initial failures (contingencies). The Cascades module utilizes an UFLS scheme that is based on the Swissgrid transmission code 2013 [9]. Table 4 shows the UFLS actions undertaken by Cascades during under-frequency events. The table shows that all units are disconnected when the frequency goes below the 47.5 Hz threshold. This measure is also applied for frequency larger than 51.5 Hz. Furthermore, Cascades uses UVLS procedure to restore voltage below 0.92 p.u. For that purpose, at the buses where voltage violation is detected, a stepwise load shedding routine removes 25% of the load at each step until the voltage is restored. To generate the sets of contingencies we use only one failure probability for all lines and transformers in the system, with a default value of 0.001.

More on the Cascades UFLS scheme, UVLS procedure, and the generation of the contingencies can be found in the "Cascades Module Documentation" report.

Table 4: The UFLS data used in the Cascades module.

Frequency, f (Hz)	**Action**	**Cumulative load shedded (%)**
49.8 $<$ **f** $\geq$ **49.5**	Activate reserves	-
49.5 $<$ **f** $\geq$ **49.0**	Disconnect pumps	-
49.0 $<$ **f** $\geq$ **48.7**	Disconnect pumps + Load shedding	15
48.7 $<$ **f** $\geq$ **48.4**	Disconnect pumps + Load shedding	25
48.4 $<$ **f** $\geq$ **48.1**	Disconnect pumps + Load shedding	40
48.1 $<$ **f** $\geq$ **47.5**	Disconnect pumps + Load shedding	60
f $<$ **47.5**	Disconnect all units	-

1.2 Distribution grid

Nexus-e represents the distribution grid on an aggregated cantonal level. Most data used for the distribution grid (e.g., wholesale prices and reserve requirements) are internally calculated within the Nexus-e framework. While we do not model the distribution grid, we connect the cantonal values (e.g., electricity load profiles) to the nodes of the transmission grid. The Investment loop exemplifies this cantonal-node connection: First, CentIv provides to Distributed Investments Module (DistIv) the nodal electricity load and wholesale prices, along with the Swiss reserve requirements. In turn, DistIv sums the nodal values for each canton and also calculates the cantonal wholesale prices using a weighted average of the prices of all nodes within each canton. The weights are defined as the ratio of the hourly nodal load to the hourly total load in each canton. Similarly, for the reserve requirements, we also use the weighted average. After DistIv identified the cost-optimal investments into distributed energy resources, it sends nodal residual demand and reserve requirements back to CentIv. To allocate the cantonal values to the multiple nodes in the canton, DistIv uses the same weights to disaggregate the cantonal value. Please note that while most cantons have multiple transmission nodes, six cantons have none. We include these cantons in nearby cantons with a transmission node[1].

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 multiplied by a factor of 1.2[2].

[1] Including data without transmission node into nearby cantons is necessary as input data such as network tariff, injection tariff and investment potentials of different resources are provided on a cantonal level.

[2] This means that for each region, the sum of the hourly net load and the hourly upward reserve minus the downward reserve should not be greater than 120% of the regional peak demand.

2 Electricity supply

A wide range of data are needed to implement realistic models of generators within a power system. This section details the data used in Nexus-e to represent generators at the centralized (i.e., transmission system) level for Switzerland (Section 2.1) and the neighboring European Union (EU) countries (Section 2.2) as well as to represent generators at the distribution level of Switzerland (Section 2.3).

2.1 Swiss centralized generators

In this section, the necessary data and sources are presented for the Swiss generators located at the centralized level (i.e., transmission system level) of the energy system. These data include: the capacities and operating parameters (Section 2.1.1), the hydro inflow profiles and storage volumes (Section 2.1.2), the production profiles and placement for renewable energy source (RES) units (Section 2.1.3), the candidate unit capacities and placement (Section 2.1.4), and the generator costs along with fuel prices (Section 2.1.5).

2.1.1 Capacities and operating parameters

For existing Swiss generator capacities and locations, we use data from the Bundesamt für Energie (BFE) [10, 11, 12, 13] and previous studies [14]. Additionally, operational parameters for the different technology types are taken from available literature [15] as well as previous works [16]. Table 5 lists the operating parameters used for modeling the Swiss generation fleet along with the number of units and the total installed capacity for all units of each technology type. These parameters are used in the 2015 calibration simulation as well as the 2020-2050 scenario simulations. The total capacities listed represent those existing in 2020, which we assume also remain in place until 2050. For the 2015 calibration simulation, several hydro pump units are not included[3] because these units were commissioned between 2018 and 2019 and additional nuclear units are included[4] since they were still operational in 2015.

The thermal efficiency, given in MWh of electricity (MWh_e) per MWh of thermal energy from fuel (MWh_{th}), represents the heat rate of the power plant and is used to quantify the fuel needed and associated fuel costs to produce any amount of electricity in MWh. Similarly, the CO_2 rate, given in tons of CO_2 per MWh of electricity produced, represents the emission rate of the power plant and is used to quantify the CO_2 costs to produce any amount of electricity in MWh. The ramp rate indicates how fast a generator can increase or decrease its level of electricity production and is given as a percentage of the generator's rated capacity per minute. The minimum up and minimum down time indicate how many hours a unit must stay on or off once turned on or off. Blanks in these data indicate that the parameter does not apply to a technology type (e.g., there is no thermal efficiency for generators that do not consume fuel) or that the parameter is not constrained in the model (e.g., the ramp rate for a gas simple cycle (SC) generator is fast enough that it can easily reach its rated capacity in less than one hour). Since we do not model the heating sector in Nexus-e, existing combined heat and power (CHP) units operate similar to normal gas-fired or oil-fired power generation units. We do not include carbon dioxide (CO_2) levy refund for gas-fired CHP plants. Furthermore, we do not include a market premium for hydro power.

In addition to these generators, a range of candidate units are modeled as potential investments.

[3]The new hydro pump units include: Limmern (2018), Nant de Drance (2019), and Veytaux (expanded in 2018).
[4]Both Beznau A and Muehleberg were still operational in 2015.

Table 5: Operating parameters for Swiss generators. Number of units and total capacities are for the 2020-2050 simulations (additional data for the nuclear phase-out can be seen in Section 7).

Technology Type	**Number of Units**	**Total Capacity [MW]**	**Thermal Efficiency [MWh_e/MWh_{th}]**	**CO_2 Rate [ton/MWh_e]**	**Ramp Rate [%/min]**	**Minimum Up Time [hr]**	**Minimum Down Time [hr]**
Hydro Dam	75	7957	-	-	-	-	-
Hydro Pump	22	4655	-	-	-	-	-
Hydro RoR	150	3957	-	-	-	-	-
Nuclear	3	2645	0.33	-	1.00	24	24
Lignite	0	0	0.43	1.00	1.00	12	12
Coal	0	0	0.46	0.91	1.00	12	12
Gas CC	2	102	0.58	0.40	1.67	1	1
Gas SC	2	63	0.40	0.57	-	1	1
Biomass	22	229	0.45	-	0.76	8	6
Oil	1	25	0.39	0.50	1.67	2	2
Wind	6	75	-	-	-	-	-
PV	29	717	-	-	-	-	-

While the operating parameters for these units are the same as the values listed in Table 5, information regarding the number of units and total capacity by technology type can be found in Section 2.1.4.

For the outage periods of the Swiss nuclear reactors we used data from [17]. All Swiss nuclear reactors have a refueling outage every 12 months. Therefore, we assume that the planned refueling outages are occurring in the same period in all future scenario-years. Table 6 shows all modeled outages for each of the Swiss nuclear reactors in 2015 (second column) and the planed refueling outages for the reactors still operating in 2020 until the end of their lifetime (third column). The lifetime of the Swiss reactors depends on the simulated scenario (see Section 7).

Table 6: The outage schedules of Swiss nuclear reactors for the 2015 reference year and future scenario-years.

Reactor	**2015**	**2020 - end of lifetime**
Beznau 1	weeks 11-53 (43 weeks)	weeks 17-20 (4 weeks)
Beznau 2	weeks 32-50 (20 weeks)	weeks 32-35 (4 weeks)
Goesgen	weeks 23-26 (4 weeks)	weeks 22-25 (4 weeks)
Leibstadt	weeks 34-38 & 41-43 (8 weeks)	weeks 23-26 (4 weeks)
Muehleberg	weeks 32-35 (4 weeks)	not in operation

2.1.2 Hydro inflows and storage volumes

In addition to the parameters for hydro generators provided in Table 5, more input information is needed to represent the natural water inflows for all hydro generator types and the storage volumes of hydro dams and pumps.

For the hydro dam and pump units, an original hourly inflow profile is derived from the known monthly production [18] and weekly storage levels [19] of the Swiss hydro storage units (dams and pumps); a second original profile is derived using the known monthly production of Swiss hydro run of river (RoR) units [18]. Based on the Swiss hydro generator capacities, these profiles are scaled and applied to each hydro dam/pump and RoR unit in Switzerland as well as the aggregate units in the surrounding countries. The original hydro profiles are one of the input data parameters adjusted during the calibration process. After the initial simulations during the calibration, it was clear that these original profiles did not yield correct annual production from the non-Swiss hydro units; so, separate profiles are created for the surrounding country dams/pumps and RoR units to correctly reflect the expected annual production while maintaining the same hourly profile patterns of the original Swiss profiles. Additionally, it was evident that applying the same inflow profile to pumps and dams yielded only minimal use of pumping for charging (i.e., the natural water inflows to dams were so high that little pumping was necessary); therefore, the Swiss and neighboring regions' pump profiles are scaled down so the magnitudes of the discharging and charging from pump units reflect the historical data for each region closely. It is important to note that the process of creating realistic inflow profiles for Swiss hydro dams and pumps is complicated by the fact that historical data for these two generator types are always combined, even though these generator types tend to operate in very different cycles and behaviors. More on the hydro profile calibration can be found in the "Validation and Calibration of Modules" report.

In this work, the complex networks of cascading reservoirs and hydro generators that form the Swiss hydro generation fleet are not modeled in a high level of detail. Instead, we represent each hydro dam unit as being connected to an individual reservoir and each hydro pump unit as being connected to a single upper and single lower reservoir of equal sizes. To represent the volumes of these reservoirs, data are collected on the actual volumes of existing reservoirs and the elevation difference between the reservoir and the connected generator [12] to calculate the potential energy of the full reservoir. For hydro pumps, we utilize these calculated energy volumes. However, because of the complexity of the cascades in Switzerland (e.g., some reservoirs are connected to multiple dam units), allocating an individual reservoir volume to each hydro dam is not straightforward. For this reason, a simpler approach is applied for hydro dams. To define an energy volume for each individual hydro dam, we assume that each reservoir is sized similarly and can provide continuous discharging for an extended period of time. Since we know the total energy volume of all hydro dam and pump units in Switzerland in 2020 is around 8.85 TWh, and we already fix the hydro pump volumes based on the potential energy calculation (the sum of all pumps provide around 1.98 TWh), we can define a common length of continuous discharging time for all hydro dam units to achieve the desired Swiss total energy volume. To reach the 8.85 TWh, we define the energy volume of all hydro dam units such that they each can continuously discharge for 863 hours. This assumption also enables these dam units to follow the expected long-term (i.e., seasonal) behaviors.

All hydro storage units (dams and pumps) are set with a common starting and ending energy level for their reservoirs based on data from BFE on the historical weekly storage levels [19]. Since 2015 is used for the calibration, we also apply this year's initial energy volume (i.e., 63%) for all 2020-2050 simulations. The known energy volume at the end of 2015 (46%) is applied for the 2015 calibration, while we set the ending volume equal to the starting volume (63%) for the 2020-2050 simulations.

2.1.3 Renewable production and placement

In addition to the parameters for wind and photovoltaic (PV) generators provided in Table 5, more input information is needed to represent their hourly production profiles and their placement within the Swiss transmission grid. Both of these additional inputs rely heavily on data available from previous works as part of the AFEM (Assessing Future Electricity Markets) project [14] that included detailed assessments of the RES potentials and generation profiles.

To represent the existing wind generators in Switzerland, capacity and location data are gathered from the BFE geodata platform for wind energy plants [12] for all moderately sized wind turbines (i.e., all installations with greater than 1.0 MW of wind capacity). The geographical location of these wind farms is used to define their electrical location within the Swiss transmission system; in most cases the wind capacity is placed at the nearest electrical node. The largest of these wind farms, Mt Crosin, is placed at the Bassecourt node based on feedback from Swissgrid. The hourly production profiles for these existing units are set based on a generation-weighted share of a scaled version of the AFEM 2015 Swiss hourly wind production profile [14]. The scaling is done to ensure that the total wind generation matches the historical total for the 2015 calibration year [20].

Additionally, to model potential future investments in wind farms at the centralized (transmission) level, the seven locations with the highest potential are identified from the detailed assessment conducted in the AFEM project [14]. In total, the capacities of these wind farms amount to nearly 2 GW with an annual production of almost 4 TWh. Since the locations for potential future wind farms are heavily restricted within Switzerland [21], these seven candidate locations are the only options included in the Nexus-e platform. The hourly production profiles for these candidate wind units are utilized from the previous work in AFEM.

To represent the existing PV generators in Switzerland, all locations providing at least 1% of the total Swiss PV production are identified from the AFEM assessment [14]. Twenty-nine locations are therefore selected along with the appropriate capacities for implementation in the Nexus-e platform. The hourly production profiles for these existing units are set based on a generation-weighted share of a scaled version of the AFEM 2015 Swiss hourly PV production profile [14]. The scaling is done to ensure that the total PV generation matches the historical total for the 2015 calibration year [20].

2.1.4 Candidate generators

For centralized capacity expansion planning, we include candidate units for gas combined cycle (CC), gas SC, biomass, and wind, as shown in Table 7. The total candidate capacity for each technology type is based on potentials provided by [22, 23]. It is important to note that in accordance with these PSI reports [22, 23], investment costs for these centralized units are assumed constant throughout the scenario-years (see data related to gas-fired power plants in Figure 15.8 of [23] and discussions related to the uncertainty of wind costs in Section 7.3.1 [22] and Section 8.5.5 [23]). No investment subsidy is included to offset the investment costs for new gas-fired units. The costs of biomass reflect current waste incineration subsidies [22, 23], which we expect to continue in the future. The considered subsidies offset a large portion of the investment and operating costs for the candidate biomass units as well as the existing ones. We restrict the total candidate capacity of biomass to account for limited resource availability [22, 23]. We also limit the total candidate capacity of wind power to be in line with the review on the potential of wind power in Switzerland in [23]. Wind candidates are included that in total produce around 4.0 TWh/a, which is also consistent with the Swiss wind energy concept [24]. Due to the uncertainty of future cost projections of wind projects in Switzerland [22, 23], we assume constant investment costs in the period 2020-2050, but also include a sensitivity analysis of wind investments in the Scenario Results Report. The current production subsidy (KEV) is not included for wind candidate units since KEV is scheduled to phase out in 2022 and it is unlikely any new wind turbines would get accepted into the KEV before then. We do not consider candidates for new hydro investments because of the need for extensive information about the location and costs for expansion of existing hydro or new hydro units. Therefore, we also do not include investment grants for hydro power. In the scope of this project, we do not include geothermal units as candidates, hence, we do not include subsidies for geothermal. The main reason for not including geothermal capacities was the high level of uncertainty regarding the potential and costs of this technology in Switzerland [22, 23]. Due to this uncertainty, the additional computational burden to simulate geothermal power plants and the researchers' time required to set up all necessary parameters and locations for the candidate units was deemed too high. It is important to note that we do not include candidate units in the neighboring countries and instead endogenously fix future capacities based on the 2016 EU reference scenario from PRIMES [25], as shown in Section 2.2.

Table 7: Data for candidate units at the transmission system level in Switzerland (2020–2050)

Technology	Size [MW]	Number of Units	Total Capacity [MW]	Lifetime [yrs]
Gas CC	200	14	2800	30
Gas CC	100	14	1400	30
Gas SC	50	14	700	30
Biomass	20	12	240	20
Wind	-	7	1960	20

The gas candidate units are placed at system nodes with nuclear power plants where appropriate infrastructure exists (i.e. Beznau A, B, Muehleberg (220 kV) and Goesgen (380 kV)) or at locations where new developments were discussed (i.e Chavalon and Cornaux). We differentiate between different sizes of gas candidate units (50 MW / 100 MW / 200 MW) as shown in Table 7 as well as different technologies (Open/Combined Cycle). We also include multiple candidates of the same size at each system node. Candidate biomass units are located at the 6 substations with the largest power output from currently existing waste incineration power plants. As described in Section 2.1.3, for large-scale wind installations, the placement of candidate units is based on the seven locations with the highest wind potential determined in AFEM [14].

2.1.5 Generator costs and fuel prices

To represent the variable operating costs of all Swiss generators (existing and candidates) along with the investment and fixed costs associated with building a new generator in Switzerland (candidates only) we use data from recent BFE sponsored studies [22, 23]. Table 8 lists these costs by technology type.

The costs of biomass reflect current waste incineration subsidies [22, 23], which we expect to continue in the future. It is important to note that we assume constant investment costs and fixed costs throughout the scenario-years for the candidate units. Similarly the VOM cost for each technology type is the same in the 2015 calibration year and in the 2020-2050 scenario-years; 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. Table 9 lists the fuel prices and CO_2 price for the 2015 reference year, which were provided by [22, 23], and the prices for the 2020-2050 scenario-years, which were adopted from the 2016 EU reference scenario data in [25].

Table 8: Cost parameters for Swiss generators. Variable operation and maintenance (VOM) cost is used for the 2015 and 2020-2050 simulations. Fixed operation and maintenance (FOM) and investment costs are used for the candidate units in the 2020-2050 simulations.

Technology Type	VOM Cost [EUR/MWh]	FOM Cost [kEUR/MW/a]	Investment Cost [kEUR/MW/a]
Hydro Dam	11.0	-	-
Hydro Pump	9.0	-	-
Hydro RoR	9.5	-	-
Nuclear	20.0	-	-
Gas CC	16.2	25.0	58.5
Gas SC	12.1	18.0	36.1
Biomass	1.0	0.0	124.8
Oil	80.0	-	-
Wind	2.5	45.4	182.4
PV	2.7	-	-

In all years, the Swiss prices for CO_2 are the same as the CO_2 prices applied to the neighboring country generators. For the 2015 calibration year, these Swiss fuel prices are unique compared to the prices set for all other EU generators, shown in Table 17. However, in the 2020-2050 scenario-years, the Swiss and EU fuel prices for natural gas, oil, and uranium are kept equal to maintain consistency with the assumptions, also taken from the 2016 EU reference scenario, for the neighboring country capacity development from 2020 to 2050 [25]. However, the prices in Switzerland for biomass are unique compared to the neighboring country generators, which reflects the current Swiss waste incineration subsidies [22, 23].

Table 9: The fuel prices (EUR/MWh_{th}) and CO_2 price (EUR/ton) for Swiss generators for the 2015 calibration year and the 2020-2050 scenario-years.

Fuel [EUR/MWh_{th}] and CO_2 [EUR/ton] Prices					
Fuel	**2015**	**2020**	**2030**	**2040**	**2050**
Gas	25.3	32.9	40.1	44.3	45.9
Oil	41.5	51.2	66.2	73.2	76.6
Biomass	0.0	0.0	0.0	0.0	0.0
Uranium	1.4	3.0	3.0	3.0	3.0
CO2	8.0	15.0	33.5	50.0	88.0

Using the VOM costs provided in Table 8 and combining the generator parameters in Table 5 with the fuel and CO_2 prices in Table 9, the total variable operating costs for Swiss generators of each technology type can be calculated for any of the years simulated. Table 10 shows these total variable operating costs for each technology type in each of the years simulated. Comparing the different Swiss technologies, renewable units provide the lowest cost electricity (i.e., biomass, wind, and PV), followed by hydro units that also have quite low operating costs (i.e., hydro pumps, RoRs, and dams). Nuclear power provides electricity at the next lowest cost, followed by the other conventional generator types (gas CC and gas SC), leaving the oil as the most expensive generator type in Switzerland. From 2020 to 2050, while the RES, hydro, and nuclear units have consistent total variable costs, the contributions from the fuel and CO_2 costs result in steady increases to the Swiss gas and oil generator types until 2050.

Table 10: The total variable costs for Swiss generators for the different years simulated. This total variable cost is a combination of the VOM cost, fuel cost, and CO_2 cost.

	Total Variable Cost [EUR/MWh]				
Technology Type	**2015**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	11.0	11.0	11.0	11.0	11.0
Hydro Pump	9.0	9.0	9.0	9.0	9.0
Hydro RoR	9.5	9.5	9.5	9.5	9.5
Nuclear	24.3	29.1	29.1	29.1	29.1
Gas CC	63.0	78.8	98.5	112.2	129.9
Gas SC	79.9	102.9	131.5	151.4	177.0
Biomass	1.0	1.0	1.0	1.0	1.0
Oil	190.3	218.8	266.5	292.7	320.4
Wind	2.5	2.5	2.5	2.5	2.5
PV	2.7	2.7	2.7	2.7	2.7

2.2 European generators

In this section, the necessary data and sources are presented for the neighboring EU generators located at the centralized level (i.e., transmission system level) of the energy system. These data include: the capacities and operating parameters (Section 2.2.1), the hydro inflow profiles and storage volumes (Section 2.2.2), the production profiles for RES units (Section 2.2.3), and the generator costs along with fuel prices (Section 2.2.4).

All generators in the neighboring EU countries are aggregated to one unit per technology type. Much of the data needed to represent these EU generator capacities are adopted from the PRIMES 2016 EU reference scenario data in [25]. Additionally, the EU generator parameters (VOM costs, CO_2 rates, and efficiencies) are based on the information provided in the "Current and Prospective Costs of Electricity Generation until 2050" prepared and published by the DIW Berlin [15]. This document comprises data from different sources, and those that we used most frequently are:

- IEA, NEA, & OECD, Projected Costs of Generating Electricity [26, 27]
- IPCC, Renewable Energy Sources and Climate Change Mitigation [28, 29]
- IRENA, Biomass for Power Generation [30]

2.2.1 Capacities and operating parameters

For the 2015 calibration, the generator capacities are defined using data from ENTSO-E [31]. In all 2020-2050 scenarios, the generator capacities are instead defined based on the installed capacity projections from the 2016 EU reference scenario [25]. Tables 11, 12, 13, and 14 provide the values for the capacities by technology type over the simulated years for each of the four neighboring countries. As part of the calibration process, some of the capacities listed have been adjusted. For instance, to achieve agreement with the annual production totals for these aggregate units, we apply capacity factors to some technology types to reduce their available capacity over the full year (for Nuclear: DE=83% & FR=85%; for Biomass: DE=65% & IT=50%). The generator capacities of each surrounding country are placed at the main country node (not at the border node).

Table 11: German generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [25].

Germany - Installed Capacity [MW]					
Technology Type	**2015**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	1518	1440	1440	1440	1440
Hydro Pump	6400	6400	6400	6400	6400
Hydro RoR	3989	3860	3860	3860	3860
Nuclear	9654	5733	0	0	0
Lignite	21 160	22 493	16 823	10 303	6929
Coal	26 190	26 677	19 952	12 220	17 071
Gas CC	22 926	19 933	24 565	39 500	39 500
Gas SC	2252	1958	2413	3758	6000
Biomass	4550	4615	4481	4720	4281
Oil	4532	1674	1248	863	674
Wind	44 680	61 832	67 214	69 404	86 549
PV	39 224	52 803	63 959	65 956	86 141

The operating parameters for the aggregate generators of all the neighboring countries are the same as those shown for the Swiss generators in Table 5; however, the ramp rate and minimum up/down time are not applied to these units since they are aggregated representations of many generators and would not be expected to match these operating limitations.

Table 12: French generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [25].

France - Installed Capacity [MW]					
Technology Type	**2015**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	8214	8214	8214	8500	9100
Hydro Pump	4965	4965	4965	5465	6065
Hydro RoR	10 314	10 314	10 314	10 810	11 400
Nuclear	47 348	47 348	47 348	36 084	27 434
Coal	4810	3856	3780	2892	2892
Gas CC	6162	8458	11 500	28 500	35 000
Gas SC	760	723	657	1827	6000
Biomass	1249	2894	3431	3508	3636
Oil	6670	5008	2679	1708	1625
Wind	10 324	22 130	30 771	36 880	57 569
PV	6196	20 535	25 382	31 850	45 200

Table 13: Italian generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [25].

Italy - Installed Capacity [MW]					
Technology Type	**2015**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	6362	4733	4733	4733	4733
Hydro Pump	4714	6453	6453	6453	6453
Hydro RoR	10 719	10 826	10 826	10 826	10 826
Coal	8800	8858	5098	2226	3802
Gas CC	50 140	49 473	40 212	43 559	86 826
Gas SC	1904	1879	1527	1654	3298
Biomass	2405	2694	2705	3076	3057
Oil	8800	8629	2332	603	128
Wind	9200	10 700	15 577	17 736	25 957
PV	18 900	20 400	24 562	27 050	56 765

Table 14: Austrian generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [25].

Austria - Installed Capacity [MW]					
Technology Type	**2015**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	4254	4449	4450	4491	4543
Hydro Pump	2971	3401	3401	3674	3717
Hydro RoR	5543	5662	5664	5716	5782
Coal	1171	804	778	72	36
Gas CC	4501	3527	2902	3046	2850
Biomass	608	778	813	1033	846
Oil	178	178	178	8	0
Wind	2404	2887	4545	5026	6803
PV	489	1193	282	2930	4009

2.2.2 Hydro inflows and storage volumes

In addition to the installed capacities of hydro generators provided in Tables 11-14, more input information is needed to represent the natural water inflows for all hydro generator types and the storage volumes of hydro dams and pumps. More details on the definition of these parameters is provided in Section 2.1.2.

Separate inflow profiles are created for the surrounding country dams, pumps, and RoR units to correctly reflect their expected annual production while maintaining the same hourly profile patterns of the original Swiss profiles. Similar to the modeling of Swiss hydro storages, we represent each aggregated hydro dam unit as being connected to an individual reservoir and each hydro pump unit as being connected to a single upper and single lower reservoir of equal sizes. To represent the volumes of these reservoirs, a simple approach equivalent to what was used for the Swiss hydro dams is applied. However, for these non-Swiss aggregate units, we define a common length of continuous discharging time for both hydro dam and hydro pump units. Each dam reservoir is sized to be able to continuously discharge for 863 hours, while each pump unit's upper and lower reservoir are sized to be able to continuously discharge for 100 hours. These sizes enable the dam and pump units to operate in the typical seasonal (dam) and daily (pump) patterns.

2.2.3 Renewable production

In addition to the capacities for wind and PV generators provided in Tables 11-14, more input information is needed to represent their hourly production profiles. Creating these profiles relies heavily on data available from previous works as part of the AFEM project [14] that included detailed assessments of these RES potentials and generation profiles.

The hourly production profiles for the wind and PV units are set based on scaling a version of the AFEM hourly wind and PV production profiles for each country in each year [14]. The scaling is done to ensure that the annual production matches the historical total for each year. Different data sources are utilized for the annual totals in the neighboring countries. For the 2015 calibration simulation, various data sources provide annual total production for wind or PV in the four neighboring countries [32, 33, 34, 35, 31, 14]. For the 2020-2050 scenario-years, the PRIMES 2016 EU reference scenario [25] is the only source used to set the annual production totals for wind and PV in each of the neighboring countries. Table 15 lists the annual totals for wind and PV in each year for the neighboring countries. Once scaled, the hourly profiles are applied in the Nexus-e platform for the corresponding neighboring country in the appropriate year.

Table 15: The annual wind and PV production (TWh) of the units located in the Swiss neighboring countries for each simulated year.

RES Type - Year	Austria	Germany	France	Italy
Wind - 2015	4.8	80.6	21.1	14.6
Wind - 2020	4.8	109.5	55.1	14.7
Wind - 2030	10.1	128.3	83.4	32.7
Wind - 2040	10.9	139.9	103.7	39.8
Wind - 2050	15.4	195.7	171.3	62.0
PV - 2015	0.9	38.7	7.4	24.7
PV - 2020	1.2	48.5	31.6	25.6
PV - 2030	3.3	60.5	41.0	34.0
PV - 2040	3.5	63.9	51.3	39.9
PV - 2050	5.1	83.0	77.2	88.0

2.2.4 Generator costs and fuel prices

To represent the variable operating costs of all EU generators, we use data from the comprehensive review done by [15]. Table 16 lists these cost by technology type for each of the Swiss neighboring countries modeled by the Nexus-e platform. Note that, several VOM costs were adjusted as part of the calibration process of the CentIv and eMark modules[5].

The VOM cost for each technology type is the same in the 2015 calibration year and in the 2020-2050 scenario-years; 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. Table 17 lists the fuel prices and CO_2 price for the 2015 reference year, which were provided by [15], and the prices for the 2020-2050 scenario-years, which were adopted from the 2016 EU reference scenario data in [25].

In all years, the prices assumed for CO_2 are the same in Switzerland and in the neighboring countries. For the 2015 calibration year, these neighboring EU fuel prices are unique compared to the prices set for the Swiss generators, shown in Table 9. However, in the 2020-2050 scenario-years, the Swiss and EU fuel prices for natural gas, oil, and uranium are kept equal to maintain consistency with the assumptions for the neighboring country capacity development from 2020 to 2050, which are also taken from the 2016 EU reference scenario [25].

Using the VOM costs provided in Table 16 and combining the generator parameters in Table 5 with the fuel and CO_2 prices in Table 17, the total variable operating costs for generators of each technology type in the neighboring countries can be calculated for any of the years simulated. Tables 18 and 19

[5]For more information regarding the calibration of the CentIv and eMark modules the reader is referred to the "Validation and Calibration of Modules" report.

Table 16: The VOM costs (EUR/MWh) of the units located in the Swiss neighboring countries.

Technology / Country	**Austria**	**Germany**	**France**	**Italy**
Hydro Dam	4.5	4.5	4.5	4.5
Hydro Pump	10.0	10.0	10.0	10.0
Hydro RoR	4.5	4.5	4.5	4.5
Nuclear	-	6.2	6.2	-
Lignite	-	9.0	-	-
Coal	14.0	5.0	29.2	19.2
Gas CC	0.5	12.0	17.0	27.0
Gas SC	-	4.0	4.0	4.0
Biomass	8.0	8.0	8.0	8.0
Oil	80.0	80.0	80.0	80.0
Wind	2.5	2.5	2.5	2.5
PV	2.0	2.0	2.0	2.0

Table 17: The fuel prices (EUR/MWh_{th}) and CO_2 price (EUR/ton) for the neighboring country generators for the 2015 reference year and the 2020-2050 scenario-years.

Fuel [EUR/MWh_{th}] and CO_2 [EUR/ton] Prices					
Fuel	**2015**	**2020**	**2030**	**2040**	**2050**
Gas	21.0	32.9	40.1	44.3	45.9
Coal	8.5	9.8	14.5	16.0	17.0
Lignite	5.1	4.4	4.4	4.4	4.4
Oil	31.8	51.2	66.2	73.2	76.6
Biomass	3.4	7.2	7.2	7.2	7.2
Uranium	3.0	3.0	3.0	3.0	3.0
CO2	8.0	15.0	33.5	50.0	88.0

below provide demonstrations of these total variable operating costs for 2020 and 2050, respectively.

Table 18: The total variable costs (EUR/MWh) for the units located in the Swiss neighboring countries in the 2020 scenario-year.

Technology / Country	Austria	Germany	France	Italy
Hydro Dam	4.5	4.5	4.5	4.5
Hydro Pump	10.0	10.0	10.0	10.0
Hydro RoR	4.5	4.5	4.5	4.5
Nuclear	-	15.3	15.3	-
Lignite	-	34.2	-	-
Coal	49.0	40.0	64.1	54.1
Gas CC	60.9	72.4	77.4	87.4
Gas SC	-	98.4	98.4	98.4
Biomass	24.0	24.0	24.0	24.0
Oil	218.8	218.8	218.8	218.8
Wind	2.5	2.5	2.5	2.5
PV	2.0	2.0	2.0	2.0

Table 19: The total variable costs (EUR/MWh) for the units located in the Swiss neighboring countries in the 2050 scenario-year.

Technology / Country	Austria	Germany	France	Italy
Hydro Dam	4.5	4.5	4.5	4.5
Hydro Pump	10.0	10.0	10.0	10.0
Hydro RoR	4.5	4.5	4.5	4.5
Nuclear	-	15.3	15.3	-
Lignite	-	107.2	-	-
Coal	131.0	122.0	146.2	136.2
Gas CC	109.6	121.1	126.1	136.1
Gas SC	-	180.4	180.4	180.4
Biomass	24.0	24.0	24.0	24.0
Oil	320.4	320.4	320.4	320.4
Wind	2.5	2.5	2.5	2.5
PV	2.0	2.0	2.0	2.0

2.3 Swiss distributed generators

The modeled distribution system consists of six types of distributed energy technologies, namely PV, biomass wood, biomass manure, CHP, grid-battery, and PV-battery. Grid-batteries charge during low electricity price periods and discharge during high electricity price periods to make inter-temporal market arbitrage. PV-batteries have no direct connection to the grid and in general charge (discharge) when the demand of the PV investor is lower (higher) than his PV generation. Table 20 provides an overview of key parameters for these technologies, using 2018 as the reference year (if not specified otherwise). For the distributed generation technologies we use the data from [23], while for grid-battery and PV-battery, we use the information on the Tesla Powerpack and Powerwall 2 [36]. We assume that PV-batteries have a ratio of 13.5 kWh to 5kW, meaning that a 27 kWh battery has a capacity of 10 kW. This ratio is based on the Tesla Powerwall 2. PV-batteries are continuously sized, meaning that they can have every size, but they utilize the above mentioned ratio between size (kWh) and capacity (kW). We choose continuous sizing because we consider PV-battery investments on a cantonal level. Furthermore, we do not include any subsidies for batteries. The total cost of installing Tesla Powerwall 2 is calculated assuming that the battery pack costs available on [36] account for 46% of the total investment costs [37]. We include decreasing investment and operation costs for PV and batteries until 2050, while all other parameters remain constant. The current production subsidy (KEV) is not included for the PV candidate units since KEV is scheduled to phase out in 2022 and it is unlikely any new PV would get accepted into the KEV before then. Table 21 presents the assumptions on the development of PV and storage investment and operation costs, presented in percentage of the reference year 2018 based on [23].

Table 20: 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

Table 21: Assumptions for future investment and operational costs.

(a) Investment costs

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

(b) Operational costs

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

We include four PV categories (i.e., 0-10 kWp, 10-30 kWp, 30-100 kWp, >100 kWp) and limit the maximum installed capacity for each category according to its PV potential, which we calculated based on the Sonnendach data [38] assuming the area required for 1 kWp of PV is 6 square-meters. PV potentials in Switzerland are shown in Figure 2 and Figure 3. Not all cantons are shown in Figure 2 as PV potentials of cantons without transmission nodes are aggregated into the nearby cantons. For PV electricity generation, we use irradiation data from MeteoSwiss [39]. We assume a linear degradation rate of 0.5% per year for PV panels (i.e., each year the annual PV output decreases by 0.5%) [40]. Details of the grid tariff, PV injection tariff and the wholesale-to-retail price margin that are used to model profitability of PV investments can be found in Section 5.

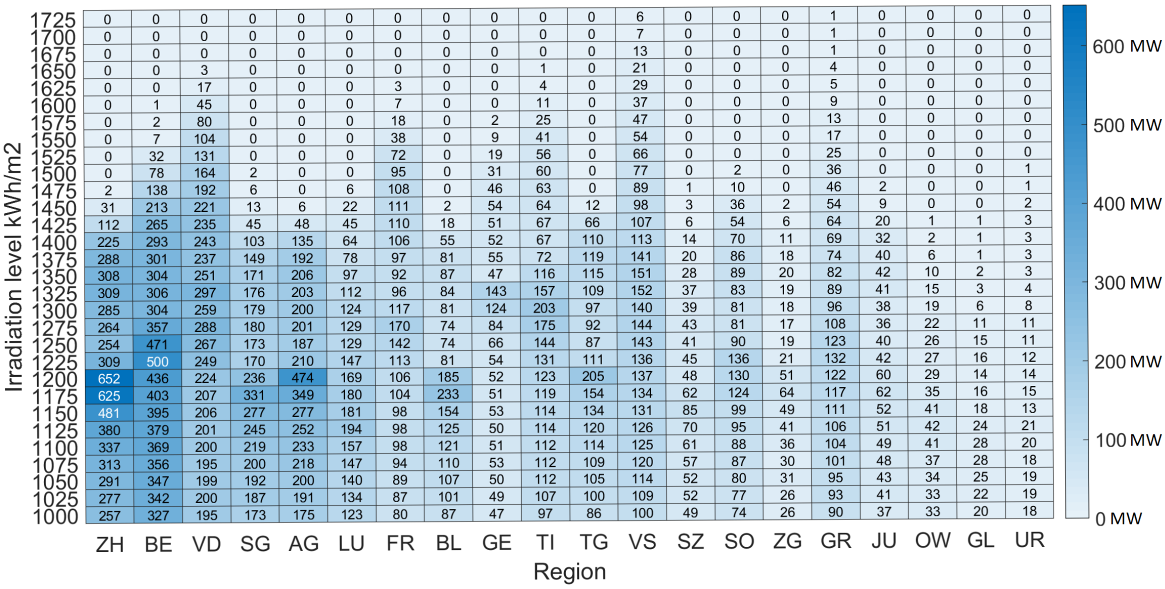


Figure 2: PV investment potential for different regions in MW.

For the investment potential of biomass technologies, we use the data from [23]. We do not limit the investment potential for CHP. In the investment decision for CHP units, we include their carbon emissions and the respective costs due to the CO_2 levy. However, we do not consider the CO_2 levy refund. Furthermore, no investment subsidy is included to offset the investment costs for new CHP. We do not include self-consumption of CHPs and, instead, assume that CHP owners sell the electricity at the wholesale market. We do so, as we assume that larger investors install CHP units and not individual households. For biomass wood/manure and CHP units, we assume a capacity factor of 0.54, 0.78, and 0.28 [23], respectively. These dispatchable generation units have a ramp rate limit of 25% of their maximum capacity per hour. Technical parameters of the candidate battery units are in Table 22.

Table 22: 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

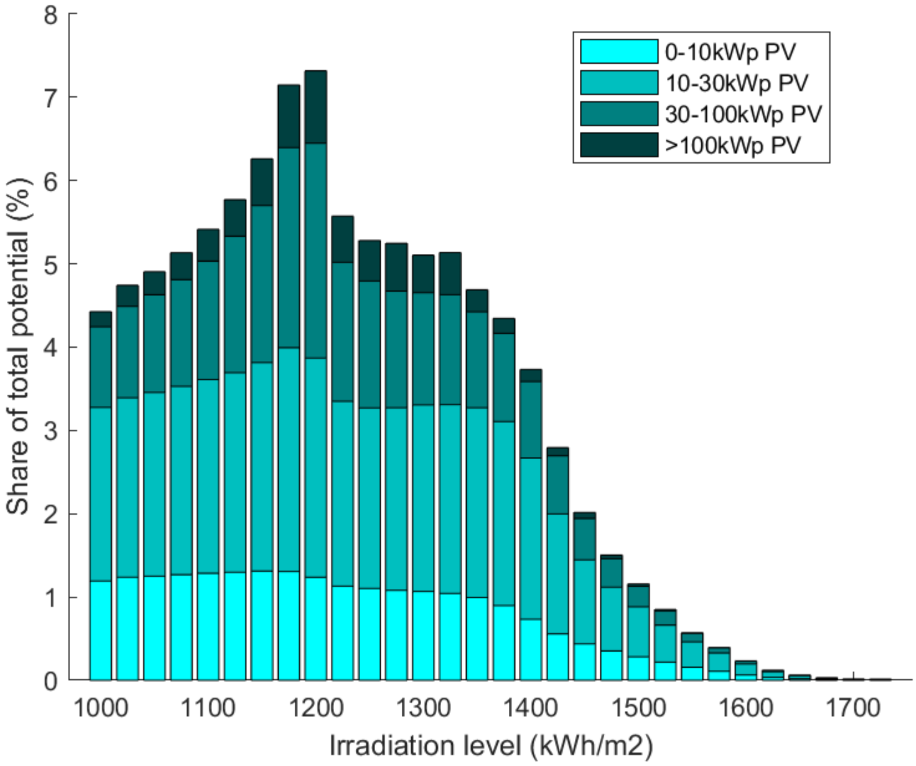


Figure 3: Distribution of PV investment potential for different categories.

3 Electricity demand

In this section, data and sources are detailed that are necessary to represent the Swiss and neighboring country electricity demand (Section 3.1) as well as the potential of demand-side management (DSM) in Switzerland (Section 3.2).

3.1 Swiss and European demand

To represent the electricity demand of Switzerland and the neighboring EU countries, we utilize available data for the 2015 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 2015 profile of the hourly electricity demand is available from Swissgrid [41]; while for the hourly profile of neighboring countries, we use 2015 data available from ENTSO-E [42]. These profiles are all for the year 2015 and are used directly for the 2015 calibration simulation. However, in all 2020-2050 scenario-years, these profiles are scaled to ensure that the annual electricity demand for each country matches the desired totals for any scenario-year. The annual Swiss demand values for the 2020-2050 scenario-years are taken from the POM scenario of the recent BFE-sponsored study on System Adequacy [43, 44]. While the annual neighboring EU country demand values for 2020-2050 are taken from the PRIMES 2016 EU reference scenario [25]. Table 23 shows the annual total loads for Switzerland and the neighboring countries in each year simulated.

Table 23: Annual electricity demand (MWh) for Switzerland and the neighboring countries for the 2015 reference year and the 2020-2050 scenario-years.

Country / Year	2015	2020	2030	2040	2050
Switzerland	62,626,000	62,038,000	62,397,000	63,852,000	65,498,000
Austria	69,600,000	65,400,000	70,600,000	75,600,000	80,700,000
Germany	520,600,000	499,400,000	526,300,000	533,200,000	546,000,000
France	475,400,000	447,600,000	464,500,000	503,300,000	541,900,000
Italy	314,300,000	301,800,000	311,200,000	356,300,000	391,700,000

In addition, the neighboring loads are further adjusted to account for cross-border flows to all other EU countries (e.g., DE-DK, DE-PL) using the 2015 cross-border flow data from ENTSO-E [45]. These cross-border flows are maintained in the 2020-2050 scenario-years (i.e., the cross-border flows to these additional EU countries in 2020-2050 are assumed to stay equal to their 2015 values). Table 24 shows the net annual cross-border flows between Swiss neighboring countries and the other EU countries.

Table 24: The net annual cross-border flows in MWh between the Swiss neighboring countries and the other EU countries.

AT to CZ	**AT to HU**	**AT to SL**	**DE to CZ**	**DE to DK**	**DE to LU**	**DE to NL**
-12,297,423	2,128,089	4,536,757	179,744	-2,246,370	6,000,000	23,687,092
DE to PL	**DE to SE**	**FR to BE**	**FR to GB**	**FR to ES**	**IT to SL**	
10,766,905	-1,732,070	8,279,660	14,156,439	7,256,517	-6,167,641	

The total hourly Swiss demand is subsequently split across the transmission grid nodes within Switzerland using population data with municipal resolution for 2015 from the Bundesamt für Statistik (BFS) [46]. Having the municipal borders from swisstopo [47] and knowing the locations of the transmission grid nodes, we assign the population of each municipality to the nearest bus node using Voronoi polygons. Consequently, we split the total hourly demand profile using the ratio of population at each node over the total population. We keep this split in all future scenario-years. This methodology relies on the assumption that demand is proportional to population density, but ignores other influencing factors such as the location of heavy industry, retail, etc.

For several of the Nexus-e module simulations, the possibility to shed load is included as a last alternative to achieve a balance between supply and demand. We apply a cost of load shedding at any node in any hour of 10′000 EUR/MWh [48].

3.2 Demand side management

In addition to the five distributed energy technologies, we also consider DSM. Table 4 presents the values for the total maximum power that can be shifted per hour, and the total energy that can be shifted per day. These numbers represent the socio-technical DSM potential (i.e., acceptance and behavior typically limits the technical potential) and are based on [49, 50], which outline a current socio-economic DSM potential of 0.6-1.15 GW that could increase to 2.5 GW by 2030, as well as on discussions with BFE. This number is distributed to different regions based on their annual demand levels. 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. Cost for system-controlled demand shifting is set to 15 EUR/MWh while no additional cost is incurred to use PV investors controlled DSM as it is used voluntarily to decrease their electricity bills.

Table 25: Overview of DSM Potential

DSM Potential	2020	2030	2040	2050
Total maximum power that can be shifted per hour [GW]	0.70	0.90	1	1
Total energy shifted per day [GWh]	2.25	2.75	3	3

4 Reserves

Traditionally, capacity reserves provide the necessary backup power to cover the loss of a generator or a load as well as for balancing the random variability in demand. As more weather-dependent RES resources are integrated, utilizing reserves to compensate for the forecast errors that these resources introduce, is becoming more ubiquitous. The modules in Nexus-e include a detailed representation of positive (upward) and negative (downward) secondary and tertiary balancing markets in Switzerland. These include both the country-wide demand for balancing capacity (included in CentIv and eMark) as well as the deployment of balancing energy in response to contingencies (in Cascades). To account for the need for larger amounts of balance reserves, Nexus-e builds on the methodology used previously in the project AFEM (Assessing Future Electricity Markets) [14] to quantify the additional reserves needed for any amount of newly installed wind or PV capacity. The description of this methodology below is drawn from previous documentation and updated according the implementation within Nexus-e. A more comprehensive description along with detailed equations can be found in Appendix A of the Nexus-e "Scenario Results" report.

The current procedure employed by Swissgrid to quantify the amount of secondary and tertiary reserves needed uses a robust probabilistic approach [51]. This work assumes that the amounts currently being procured approximately represent the amount of reserves needed to cover for conventional issues (load variability and generator outages). During each hour of the year, Swissgrid procures on average 379 MW of Secondary reserves (upward and downward) along with 227 MW of Tertiary upward and 442 MW of Tertiary downward reserves [52]. Table 26 shows the average, maximum and minimum hourly values for each reserve requirement that Swissgrid procured in 2015. We use the data for 2015 during the calibration process and also maintain the 2015 requirements as the basis for the 2020-2050 scenario simulations[6]. All dispatchable generator types are allowed to offer their capacity for the procurement of these reserves.

Table 26: The average reserve requirements along with the maximum and minimum hourly values.

Reserve	Average [MW]	Max [MW]	Min [MW]
Primary	75	75	75
Secondary Up	379	420	365
Secondary Down	379	420	365
Tertiary Up	227	424	86
Tertiary Down	442	860	332

The primary reserve requirement is constant over all hours of 2015 based on ENTSO-E regulations and is kept the same for all 2020-2050 simulations. The secondary reserve requirements vary from one hour to the next over the year but we maintain the 2015 quantities as unchanged in all 2020-2050 simulations to reflect the current procedures of Swissgrid to include RES forecast errors into the quantification of only tertiary reserve requirements [51]. For the tertiary reserve, the 2015 hourly amounts are set as the base reserve requirement, (B^{+0}_{mcyt}) for upward and (B^{-0}_{mcyt}) for downward, in MW, for a given balancing market (m) in region (c) in year (y) and hour (t) and combined using a geometric sum (eqs. (1) and (2)) with the appropriate contribution to from wind, (B^{+w}_{mcyt}) or (B^{-w}_{mcyt}), and PV, (B^{+s}_{mcyt}) or (B^{-s}_{mcyt}), in MW, to cover their uncertainties and to quantify the total upward (Bal^{+}_{mcyt}) and downward (Bal^{-}_{mcyt}) reserve requirements in MW.

[6]Since the reserve requirements set by Swissgrid have not changed much since 2015, these values are adequate to represent the approximate range of the current requirements.

$$Bal^{+}_{mcyt} = \sqrt{B^{+0}_{mcyt} + B^{+w}_{mcyt} + B^{+s}_{mcyt}} \qquad \forall m, c, y, t \qquad (1)$$

$$Bal^{-}_{mcyt} = \sqrt{B^{-0}_{mcyt} + B^{-w}_{mcyt} + B^{-s}_{mcyt}} \qquad \forall m, c, y, t \qquad (2)$$

The method that is used to quantify the additional amount of secondary and tertiary reserves needed to cover for the added uncertainty of any new wind or PV capacity installed, is based on statistical calculations and methods of forecasting wind and PV generation. To quantify the contributions that wind and PV uncertainties would have, the forecast errors are calculated for every 10-minutes using time-series data for wind speed and PV irradiance in Switzerland that were provided by IDAWEB [39]. Using the Swissgrid confidence threshold of 99.9%, the reserve contribution factors from eqs. (1) and (2) are calculated from the wind and PV forecast errors and combined with the base reserve requirements to yield the total system reserve requirements.

The selected reserve methodologies for quantifying operating reserves necessary for added wind and PV power represent some of the most recent and advanced literature [53, 54, 55, 56]. The most relevant literature surveyed was from the various renewable integration studies conducted by researchers and electricity markets around the world [57, 58, 59, 60]. We feel that we have chosen a methodology that advances what is seen in all operating reserve markets today and is in line with the most state-of-the-art research-based methods. The selected methodology will be able to quantify the necessary flexibility required to compensate for the additional uncertainty of wind and solar power and better enable a reliable and stable electric grid.

For wind power, the reserve procedure uses a synthetic forecast created assuming persistence of wind power production from one time period to the next (eq. (3)) where the forecasted power output ($\hat{q}^{R}_{r_w c_s (t+1)}$) of the renewable wind resource (r_w) in the Switzerland region (c_s) for the next time interval ($t + 1$) is equal to the actual wind power output ($q^{R}_{r_w c_s t}$) at the current time interval (t). This type of persistence forecast, while computationally simple, has been shown to match more complex forecast methodologies for short-term forecast horizons of up to one hour ahead [59].

$$\hat{q}^{R}_{r_w c_s (t+1)} = q^{R}_{r_w c_s t} \qquad r_w \subset r, \quad c_s \subset c, \quad \forall t \qquad (3)$$

For PV, the reserve procedure is enhanced to include the impacts of the known daily behavior of the sun. Instead of assuming the persistence of solar power output, the method uses a synthetic forecast created assuming persistence of cloudiness and accounts for the change in the clear sky solar irradiance from one time period to the next (eq. (4)). This cloudiness forecast method has been shown to achieve a significant improvement compared to the persistence method for short term solar forecast horizons [53]. This method is equivalent to assuming the forecasted power output ($\hat{q}^{R}_{r_s c_s (t+1)}$) of the renewable solar resource (r_s) in the Switzerland region (c_s) for the next time interval ($t + 1$) is equal to the actual solar power output ($q^{R}_{r_s c_s t}$) at the current time interval (t) multiplied by the ratio of the clear sky global horizontal solar irradiance between the two time intervals ($\tilde{I}^{R}_{r_s c_s (t+1)} / \tilde{I}^{R}_{r_s c_s t}$).

$$\hat{q}^{R}_{r_s c_s (t+1)} = q^{R}_{r_s c_s t} * \frac{\tilde{I}^{R}_{r_s c_s (t+1)}}{\tilde{I}^{R}_{r_s c_s t}} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \qquad (4)$$

Before utilizing this solar forecast method, we first had to develop a mathematical way to calculate the clear sky global horizontal solar irradiance over the full year with a time step size equal to that of the forecast step size (as small as 10 minutes). Once again, we conducted a thorough literature review and identified several mathematical models for clear sky solar irradiance, including the Bird model [61] and

Frouin model [62]. Both of these models calculate the global solar irradiance on a horizontal surface for a given zenith angle along with corrections for attenuation in the atmosphere due to scattering and absorptance. The Bird model was selected for this analysis because it provides the additional benefit of calculating global as well as direct and diffuse irradiance values. In addition, several models were considered for calculating the solar position (zenith angle, air mass, etc.) for any given global position and time of year including the methods of Spencer [63], Michalsky [64], and Meeus [65, 66]. The methodology from Meeus was selected for this work based on its balance between accuracy and complexity. Once combined, these models are able to estimate the solar irradiance at any location on earth over a one-year period using any user-defined time step.

Using the forecast equations for wind (eq. (3)) and PV (eq. (4)), the forecast errors are quantified for every 10-minute period over the year and the 99.9% confidence threshold is applied to calculate the wind and PV contribution factors included in eqs. (1) and (2). Therefore, the detailed methodology is used to quantify reserve demand for all types of reserve for all possible combinations of wind and solar power capacity.

5 Policies and regulations

Several exiting policies and regulations impact the economic tradeoffs involved in the optimization of new investments. In this section, we introduce the four policies/regulations that we account for in Nexus-e (Section 5.1) and also present data on how we quantify and model the consumer's retail price as part of the evaluation of PV investments (Section 5.2).

5.1 Modeled policies and regulations

To account for the impacts of the legislative and regulatory framework on the investment decisions especially for PV units, we consider: available investment subsidies, the distribution system operator (DSO) injection tariffs, tax rebates, and network tariffs. Note that the first three are only applied to PV units whereas the last one (i.e. network tariff) is applied to all units in DistIv. While the High-Flexibility scenario will make some changes to these policy factors, both the Baseline and Nuclear-60 scenarios represent the status quo for the legislative and regulatory framework (i.e., in place and planned) for the following four parts.

First, we include the current investment subsidy for PV units based on BFE regulations [67] until 2020. Beyond 2020, we assume the subsidy decreases to 80% of the 2020 level by 2030 and phases-out afterward (i.e., no investment subsidy for PV in 2040 nor 2050). Details of the modeled investment subsidies are in Appendix A. The reduction of the upfront cost of PV units from this subsidy could have a significant impact on their profitability and therefore the decision to invest in them.

Second, to account for income earned from PV generation that is fed back into the local electricity grid, we include the injection tariffs that are set by regional DSOs. Since these injection tariffs very from DSO to DSO, we use data available from [68] and make an estimation of the average value for each canton. Details of the injection tariff can be found in Appendix B. The inclusion of this injection tariff is important for quantifying the revenue earned from PV generation that is not self consumed, and even more critically, it is needed to quantify the economic benefits of the PV-batteries that help increase the earnings of the PV units by reducing the PV generation sold at this injection tariff by storing the PV generation instead and using it later as self consumption. In this work, the regional injection tariffs are assumed to be constant between 2020-2050 due to the uncertainties regarding the development of these tariffs. In the course of the analysis, it became apparent that such an assumption would result in injection tariffs below the wholesale price. This trend is not in line with the planned regulation in Switzerland, so an additional sensitivity simulation was conducted (see Section 4.1.4 of the Scenario Results report) where the injection tariff expires in 2025. It can therefore be stated that the PV development in the Baseline scenario is conservative, as is also illustrated by the development in the calculated sensitivity.

Third, we also consider the available tax rebates of 7.7% on the operational costs and 20% on the net investment costs (i.e., excluding the investment subsidy) [69] in all cantons except Luzern and Graubünden due to regional regulations [70]. We assume these tax rebates to remain constant until 2050.

Fourth, within the consumer's electricity cost, we also represent the network tariff component. For this network tariff, we use the data for 2018 from ElCom (including grid charge and additional fees) [71] and assume the network tariff remains constant until 2050. The network tariff comprises a significant part of the consumer's electricity cost and is therefore important to properly represent the savings earned when this cost is reduced by self consuming ones own PV production. The network tariff applied for each PV category is listed in Appendix C.

While the policies and regulations listed above are accounted for in the modeling framework, a range of other existing or possible future policies are not included in this assessment. These include:

- no investment subsidies for gas-fired candidate units are applied because no direct investment subsidy is expected for these units (see Sections 2.1.4 and 2.3 for more details);
- no CO_2 exoneration for gas-fired CHP plants is included because we do not implicitly model the heating sector and only model the few CHP units that are of reasonably large enough size to contribute to the electricity market (see Section 2.3 for more details);
- no subsidies for wind generators are include because the current production subsidy (KEV) is scheduled to phase out in 2022 and it is unlikely any new wind turbines would get accepted into the KEV before then (see Section 2.1.4 for more details);
- no subsidies for new geothermal candidates are included because we do not consider candidates for new geothermal investments as a result of the high level of uncertainty regarding the potential and costs of this technology in Switzerland [22, 23] (see Section 2.1.4 for more details);
- no investment grants for new hydropower candidates are included because we do not consider candidates for new hydro investments as a result of the need for extensive information about the location and costs for expansion of existing hydro or new hydro units (see Section 2.1.4 for more details);
- no subsidies for batteries are included because such subsidies are currently set by local Cantonal authorities with very few having approved of this subsidy and the future implementation of such a subsidy is uncertain (see Section 2.3 for more details).

5.2 Modeling the consumer retail price

Within the DistIv module of Nexus-e, the price of electricity for purchasing from or selling to the transmission grid comprises two parts: (i) the wholesale electricity price (signal from CentIv) and (ii) the network tariff (including both the grid charge and additional fees). However, as mentioned in the "DistIv Module Documentation" report, to properly reflect the consumer costs that are offset by self-consuming from PV, we model the consumer's retail electricity price by including a third component: (iii) the wholesale-to-retail price margin (shown in Appendix D). Out of these three parts, the price margin and network tariff are kept constant over all simulated years, while the wholesale price provided by CentIv is expected to vary over future years. Therefore, the combined retail electricity price seen by the consumers will also varies from year to year; in general, the consumer price increases further into the future due to the increases in CO_2 and fuel prices. More details of how we calculate the network tariff portion and the wholesale-to-retail price margin portion are described in the following paragraphs.

The network tariff portion of the consumer price is different for different categories of users (H1-H8, C1-C7, i.e. 15 categories based on the cantonal network tariff data provided by ElCom [71]). We calculate the weighted-average network tariff for each canton by analyzing the proportions of different categories in each canton as follows:

- Split the total electricity consumption between households, industry, transportation and service based on [72];
- 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)" [73];
- Further split consumption from industry and service areas based on the information about the number of employees they have provided by "Statistik der Unternehmensdemografie" [74].

For the wholesale-to-retail price margin portion of the consumer price, instead of using one fixed value for all cantons and all units, we quantify unique values of this price margin for each canton and each PV category. The margin is calculated as the difference between the historical 2018 consumer price (data for each canton from Elcom [71]) and the combination of the 2018 wholesale price (provided by CentIv) and the cantonal network tariff (data from Elcom [71]). As the consumer prices are different for different consumer categories (in total 15), different PV unit groups are assigned to different consumer price categories based on the annual consumption information for each consumer 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 PV investment subsidy, the injection tariff, the network tariff, and the detailed price margins applied for each PV category are listed in Appendix A, Appendix B, Appendix C and Appendix D, respectively.

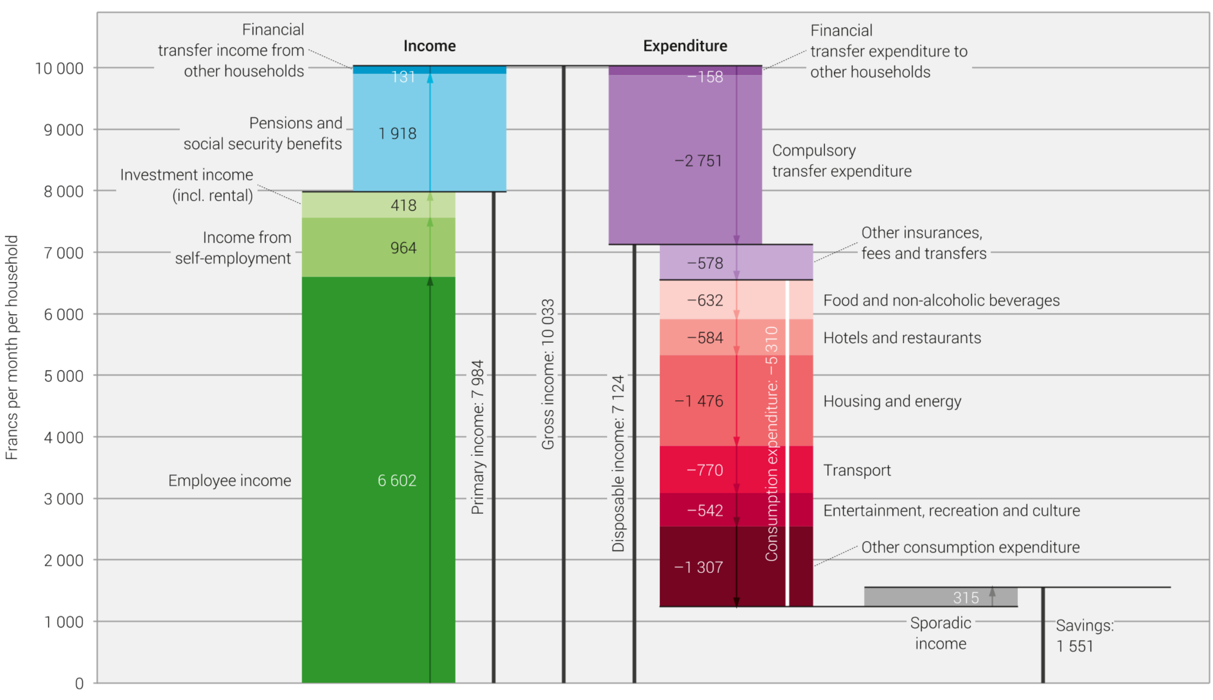
6 Economy

The General Equilibrium Module for Electricity (GemEl) module requires a number of input data and assumptions. In this section, these data and their sources are described for information related to household and sectoral data (Section 6.1), elasticities on domestic and international production (Section 6.2), and the baseline growth path used for calibrating the recursive model (Section 6.3).

6.1 Household accounts and the IOT

The database used for GemEl is the Swiss differentiated input–output table for the energy sector (IOT-Energy) of the year 2014 [75]. GemEl allows to disaggregate the representative households from the IOT-Energy into 14 separate household groups according to their income and being retired or not (10 working and 4 retired groups). This disaggregation is based on data from the household budget survey (HBS) [76]. The HBS is conducted yearly and collects all income and expenditures. Due to the rather small annual HBS sample size (around 3000 households), tables for subgroups can only be based on a pooled sample of at least three years. We use the data for the years 2012, 2013, and 2014. Figure 4, taken from [76], shows the average income and expenditure of households in Switzerland for the year 2016.

Household income and expenditure of all households, 2016



Source: FSO – Household Budget Survey (HBS)

Figure 4: Average income and expenditure of households in Switzerland for the year 2016.

Every household has a weight that secures that the total sample of around 10’000 households is a good representation of the actual households in Switzerland. If we aggregate using the household weights, we found a discrepancy between the consumer expenditure and income with the numbers in the IOT-Energy 2014. We reconciled the data to get a close match. In a first step, we use the HBS to calculate the total income and expenditure for all households in Switzerland (column "HBS" in Table 27) and compare these figures with the respective figures in the IOT-Energy, the national accounts, and other statistics (column "target"). The table shows that there are greater differences in some of the consumer goods, taxes on income, and capital income. The discrepancy in consumer good 'C02' (alcoholic beverages, tobacco, and narcotics) is a typical result in HBSs as households tend to under-report these items. Health expenditure is treated differently at the macroeconomic level and often leads to big discrepancies.

Table 27: Comparison of macro values of household expenditure and income in million CHF.

Code	Description	Source for target	Target	HBS	Difference	Factor
C01	Food and non-alcoholic beverages	IOT2014 [1]	-29'633	-26'985	-2'649	1.1
C02	Alcoholic beverages, tobacco, and narcotics	IOT2014	-8'725	-4'445	-4'279	2.0
C03	Clothing and footwear	IOT2014	-10'293	-9'502	-791	1.1
C04	Housing, water, gas, electricity, and other fuels	IOT2014	-80'983	-63'172	-17'811	1.3
C05	Furnishings, household equipment and routine maintenance of the house	IOT2014	-12'318	-11'586	-733	1.1
C06	Health	IOT2014	-59'417	-11'077	-48'340	5.4
C07	Transport	IOT2014	-27'767	-33'839	6'072	0.8
C08	Communication	IOT2014	-8'087	-7'816	-270	1.0
C09	Recreation and culture	IOT2014	-26'003	-25'450	-553	1.0
C10	Education	IOT2014	-2'060	-1'878	-182	1.1
C11	Restaurants and hotels	IOT2014	-21'995	-23'512	1'517	0.9
C12	Miscellaneous goods and services	IOT2014	-38'144	-10'548	-27'596	3.6
Lab	Labor income	IOT2014	325'381	319'468	5'913	1.0
Cap	Capital income	VGR: S14-D.4 [2]	69'230	33'396	35'833	2.1
IncTax	Taxes on income	VGR: S14-D.5	-68'555	-49'774	-18'781	1.4
Labtax	Social security contributions	BSV [3]	-42'521	-41'919	-602	1.0
Savings	Savings	VGR: S14-B.9	-77'569	-59'271	-18'298	1.3

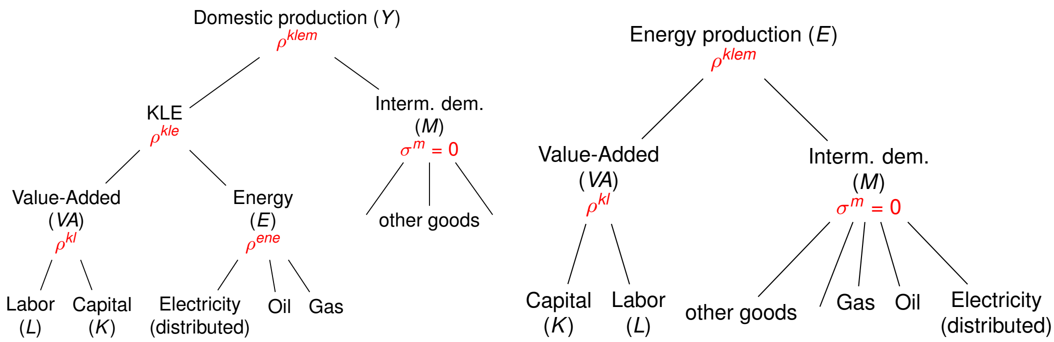
[1] Differentiated Input–Output Table for the Energy Sector 2014 [75].
[2] VGR: National income accounts [77]
[3] BSV: Federal Office of Social Insurance [78]

6.2 Elasticities for domestic production and international trade

GemEl contains over 70 sectors taken from the Swiss IOT-Energy. Each sector is treated in the model as a producer. The behavior of each producer is given by the maximization of profits defined as valued output minus the costs of the inputs. In the case of perfect competition, the producer takes the prices of outputs and inputs as given. The production technology is formulated as a nested constant-elasticity of substitution (CES) function as shown in Figure 5. We make a distinction between non-energy and energy sectors. In the non-energy sectors, substitution between energy and value-added (capital and labor) is allowed. In the energy sectors, the input of energy fuels is treated as a complementary input to value-added and other inputs to keep inputs and outputs of energy consistent.

We follow the method of Werf [79] in the choice of the substitution possibilities between capital (K), labor (L), energy (E) and intermediate demand (M). He estimates and compares the substitution elasticities of six industrial sectors for several nesting structures (*KE-L, KL-E, KLE*) and finds the highest statistical significance for the elasticities of the *KL-E*-structure. The substitution elasticity in the intermediate nest (σ^m) is set to 0, which is common practice in applied computable general equilibrium (CGE) work.[7] Table 28 contains the values or range of the chosen sectoral elasticities.

[7] A substitution elasticity of zero implies complementary goods: cars need four wheels. However, one reason for setting this value to zero, was the reduction of the complexity of the model in times when computer power was an issue.



(a) Sectors (without energy sectors)

(b) Energy production sector

Figure 5: Illustration of domestic production function

Table 28: Domestic production and Armington elasticities.

Parameter	Value or range	Description	Source
σ_i^{klem}	0.11 - 1.15	elasticity parameter between KLE and Intermediate Demand (KLEM) nest	[80]
σ_i^{kle}	0.09 - 1.27	elasticity parameter between Value-Added and Energy (KLE) nest	[80]
σ_i^{kl}	0.06 - 3.36	elasticity parameter between Capital and Labor (KL) nest	[80]
σ^{ene}	0.5	elasticity parameter between Electricity, Oil, and Gas (ene) nest	[81]
σ^{m}	0	elasticity parameter between Other Goods (m) nest	common practice in CGE modeling

In a single-country model like GemEl, sectoral output is transformed into goods produced for the domestic market and exports. Goods for the domestic market are a composite of imports and domestically produced goods, the so-called Armington good. The domestically produced good is split in domestically supplied goods and exports. The similarity between imported and domestic goods is measured by the substitution parameter ρ^a. The substitution elasticity σ^A is given by $1/(1-\rho^A)$. There is no agreement in the literature on the correct value of the sectoral substitution and transformation elasticities (see, for example [82]). Table 29 contains the values or range of the chosen elasticities.

Table 29: International trade and Armington elasticities.

Parameter	Value or range	Description	Source
σ^A	1.2 - 8.0	elasticity parameter between import and domestic production	Own calculations based on [83]
τ	1.3 - 8.0	transformation parameter between export and domestic demand	Own calculations based on [83] and [84]

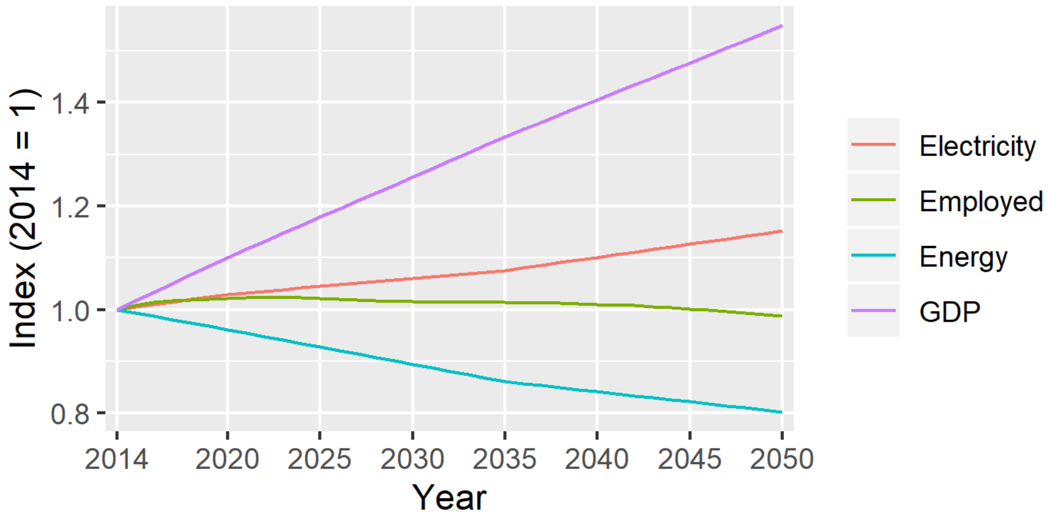
6.3 Baseline equilibrium growth path

To check if the model is correctly calibrated, meaning that it reproduces the data that serve as a starting point, the recursive model is calibrated to a steady-state baseline equilibrium growth path using the fact that on a steady-state growth path all quantities grow with the same growth rate. For Switzerland, we assume a steady-state growth rate of 1.5%. The projections for the Swiss population, gross domestic product (GDP), and the energy demand (electricity and fossil fuels) are shown in Table 30 and Figure 6. To reach the given levels, we adjust the technical progress for the energy goods to calibrate demand to the projections from the Energy Perspectives [85].

Table 30: Assumed projections for the Swiss population, GDP and energy demand according to Swiss Energy Modelling Platform [86].

Parameter	2010	2020	2035	2050	Reference
Population (million)	7.79	8.68	9.8	10.3	BFS Scenario A-00-2015
Working population (million full time equivalents)	3.853	4.31	4.58	4.63	BFS Scenario A-00-2015
GDP potential (relative to 2010)	1	1.18	1.43	1.66	Projections from: SECO 2015
Energy demand (relative to 2010)	1	0.937	0.839	0.782	BAU (WWB) scenario from BFE 2050 Energy Perspectives (p. 96)
Electricity demand (relative to 2010)	1	1.05	1.097	1.175	BAU (WWB) scenario from BFE 2050 Energy Perspectives (p. 96)
Fossil energy demand by ETS sectors (relative to 2010)	1	0.858	0.621	0.388	Simlab

Figure 6: Illustration of projections for the Swiss population, GDP and energy demand according to Swiss Energy Modelling Platform [86]



7 Scenarios

We analyze three scenarios (**Baseline**, **Nuclear 60**, **High Flexibility**) of the future Swiss power system. Each scenario simulation consists of four years (2020, 2030, 2040, and 2050), which we refer to as scenario-years. Table 31 provides an overview of the key differences between the scenarios.

Table 31: Overview of scenarios and their key differences

	Nuclear Capacity [MW]				**DSM Potential (maximum power shifted per hour [GW] / maximum energy shifted per day [GWh])**				**BSS Cost Development [% change to starting value in 2018] (Starting value: 1'156 EUR/kWh)**			
Scenario / Year	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Baseline	2645	1220	0	0	0.7 / 2.25	0.9 / 2.75	1 / 3	1 / 3	100%	72%	53%	39%
Nuclear 60	3010	2645	1220	0	0.7 / 2.25	0.9 / 2.75	1 / 3	1 / 3	100%	72%	53%	39%
High Flexibility	2645	1220	0	0	1.4 / 4.5	1.8 / 5.5	2 / 6	2 / 6	100%	36%	26.5%	19.5%

The **Baseline** scenario includes the projected development of input parameters as described in previous sections, for example, the lifetime of 50 years for nuclear power plants. It also represents the status quo of the Swiss legislative and regulatory framework (in place and planned), such as the financial subsidies for PV systems. This scenario is set as the base case based on the discussions with BFE.

The **Nuclear-60** scenario reflects the discussion about the nuclear power phase-out. It builds upon the Baseline scenario but assumes that nuclear power plants are phased-out after a lifetime of 60 years each, instead of the 50 years in the Baseline scenario. The lifetime of the plants is a crucial assumption as it defines the pace of the nuclear exit: While the update of the Swiss energy law in 2018 forbids the construction of new nuclear power plants and fundamental modifications to existing nuclear power plants, existing nuclear power plants may continue to operate as long as they fulfill the conditions for safe operation, which is decided by the Swiss Federal Nuclear Safety Inspectorate (ENSI), an independent federal authority. The lifetime of each individual power plant is, therefore uncertain and is difficult to foresee. It is important to highlight that there are no legal limits on the operating life of reactors besides the safety regulation. Table 32 compares the year of the phase-out of the nuclear power plants in Switzerland when assuming a lifetime of 60 years, compared to the 50 years in the Baseline scenario.

Table 32: Overview of nuclear power phase-out under 50 and 60 years of lifetime

Nuclear power plant/reactor	**Capacity**	**Operation since**	**Phase-out in year (runtime 50 years)**	**Phase-out in year (runtime 60 years)**
Beznau 1	365	1969	2019	2029
Beznau 2	365	1972	2022	2032
Mühleberg (KKM)	355	1972	-	-
Gösgen (KKG)	1060	1979	2029	2039
Leibstadt (KKL)	1220	1984	2034	2044

The **High-Flexibility** scenario reflects the discussion on the impact and value of an increased supply of distributed flexibility in the power system. The scenario builds upon the Baseline scenario and assumes 50% lower battery costs and 100% higher demand-side management potential for 2030-2050, compared to the Baseline scenario, while leaving the starting values for 2020 unaffected (as shown in Table 31). Thus, we only adjust the cost projections of battery storage and the DSM potential, therefore accounting for the uncertainties in the development of both parameters. For battery storage, a 2018 report by the European Commission outlines observed and reported values for battery pack prices, which range from below 200 €/kWh to above 1400 €/kWh [37]. The report also highlights that while most studies foresee strong technology learning, cost projections for future years vary substantially, for example, ranging from below 50 €/kWh to above 250 €/kWh in 2040. The main driver of battery costs development but also its uncertainty is the electrification of the transport sector and the projected electric vehicle uptake. Similarly, for DSM, calculating its current and future potential for Switzerland is challenging. Results for today's socio-technical DSM potential (i.e., acceptance and behavior typically limits the technical potential) range between 0.6 GW [49] and 1.15 GW [50] and could go up to 2.5 GW by 2030 [50]. Key drivers for increasing DSM potential are the projected uptake of electric vehicles and heat pumps. Again, the drivers of uncertainties are the diffusion of electric vehicles but also the acceptance of their owners to participate in DSM programs. We defined the values for DSM potential that we use in the Baseline scenario in collaboration with BFE. The higher values in the High-Flexibility scenario reflect the increasing DSM potential suggested in literature.

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Appendices

A Data: assumed PV investment subsidies

Table 33: The modeled PV investment subsidy decreases in 2030 and is phased-out before 2040.

	2020	**2030**	**2040**	**2050**
Basis (Fr.)	1000	800	0	0
0-30 kW PV (Fr./kW)	340	272	0	0
>30 kW PV (Fr,/kW)	300	240	0	0

B Data: assumed DSO injection tariff by canton

Table 34: The DSO injection tariff in cent/kWh for PV is estimated for each Swiss Canton.

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 Data: assumed network tariff by canton

Table 35: The weighted average network tariff in cent/kWh is calculated for each Swiss Canton.

Index	Canton	Additional fees	Grid charge	Total network 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

D Data: assumed wholesale-to-retail price margin by canton

Table 36: The calculated wholesale-to-retail price margin in cent/kWh varies by Canton and PV category.

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