Energy Science Center
Swiss Federal Institute of Technology Zurich

SOI C5
Sonneggstrasse 28
8006 Zurich, Switzerland

www.nexus-e.org

Final report

Nexus-e: Interconnected Energy Systems Modeling Platform

Input Data and System Setup

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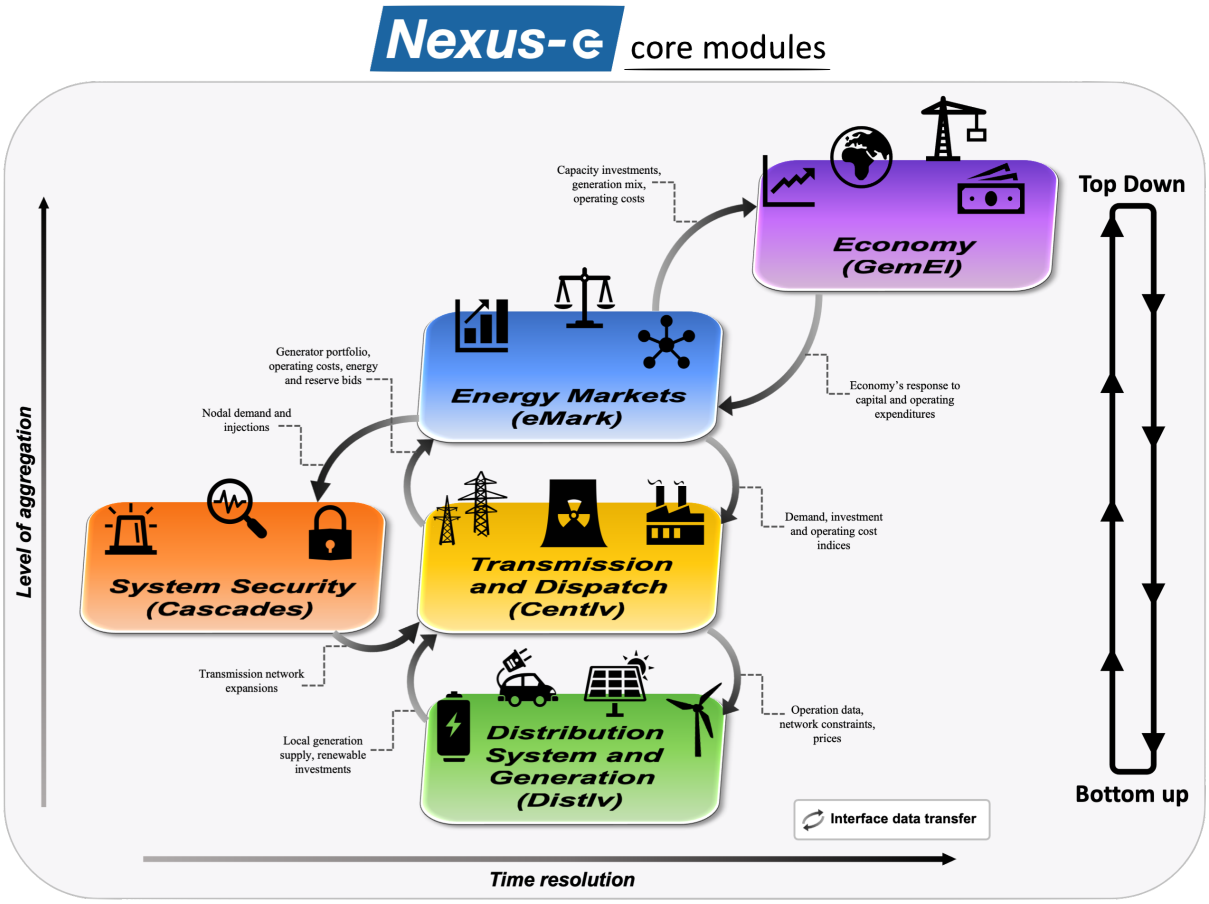

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Authors:
Jared Garrison, Forschungsstelle Energienetze - ETH Zürich, garrison@fen.ethz.ch
Blazhe Gjorgiev, Reliability and Risk Engineering Laboratory - ETH Zürich, gblazhe@ethz.ch
Pranjal Jain, Energy Science Center - ETH Zürich, pranjal.jain@esc.ethz.ch
Elena Raycheva, Energy Science Center - ETH Zürich, elena.raycheva@esc.ethz.ch
Marius Schwarz, Energy Science Center - ETH Zürich, mschwarz@ethz.ch
André Bardow, Energy and Process Systems Engineering - ETH Zürich, abardow@ethz.ch
Turhan Demiray, Forschungsstelle Energienetze - ETH Zürich, demirayt@ethz.ch
Gabriela Hug, Power Systems Laboratory - ETH Zürich, hug@eeh.ee.ethz.ch
Giovanni Sansavini, Reliability and Risk Engineering Laboratory - ETH Zürich, sansavig@ethz.ch
Christian Schaffner, Energy Science Center - ETH Zürich, schaffner@esc.ethz.ch

Project coordinators:
Project leader: Christian Schaffner, schaffner@esc.ethz.ch
Nexus-e project manager: Marius Schwarz, mschwarz@ethz.ch
Nexus-e technical project lead: Jared Garrison, garrison@fen.ethz.ch

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Summary

The characteristics of energy systems around the world are changing profoundly with increasing shares of renewable energy sources (RES), the phase-out of large base load units, the addition of large numbers of active components in the distribution system, and the electrification of heating and transportation. This transition is affecting the entire economy and the operations of the energy systems. Energy and economic system models are therefore critical to inform the decision takers and policy makers on the challenges that the energy transition may entail.

As the energy system continues to grow in complexity, so too have energy-system models as they attempt to depict future development pathways and impacts. However, this rising complexity must align with the model's target-oriented purposes to counter the ensuing computational requirements.Toward the goal of capturing interactions within the energy system, many interdisciplinary projects aim for more comprehensive assessments by connecting individual modeling tools, such as combining bottom-up and top-down approaches.However, even such linked approaches must still follow best practices, ensure they are comprehensible to others, and be fit to address the research questions at hand.

The Nexus-e Interconnected Energy Systems Modeling Platform aims to provide such a modeling tool as an interdisciplinary framework of modules that are linked through well-defined interfaces to analyze and understand the impacts of future developments in the energy system. The main objective of Nexus-e is to provide a more holistic assessment of the energy-economic system and thus to identify the cost-optimal investment in and operations of centralized and distributed electricity resources, taking into account their socio-economic impact and changes in the security of supply. The platform consists of one top-down module, i.e., a computable general equilibrium module and four high-resolution bottom-up modules, i.e., a centralized generation expansion planning and operations module, a distributed generation expansion and operations module, a market-based generation dispatch module, and a system security and transmission expansion planning module. Each target-oriented module can independently answer complementary questions related to the energy-economic system. However, when interlinked, they form an interdisciplinary platform that combines top-down and bottom-up approaches and can capture the interaction of market mechanisms that intertwine the domains of the energy-economic system. Five modules are soft-linked to create three iterative loops of Nexus-e. The modules communicate with each other through well-defined and automated interfaces. This concept allows for modularity, i.e., removing or adding modules, and therefore, further extends the modeling capabilities of the platform. Nexus-e is developed as a tool that allows the user to 1) study different scenarios of the future electricity systems and thus provide in-depth understanding of future challenges and opportunities; and 2) quantify the impacts of policies that are of interest to the decision makers and society.

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) and operations module considering system flexibility requirements,
3. Optimization-Based Distributed Investments Module (DistIv): a GEP and operations 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.

Contents

Abbreviations

AT	Austria
BESS	battery energy storage system
BFE	Bundesamt für Energie
BFS	Bundesamt für Statistik
CAGR	compound annual growth rate
Cascades	Network Security and Expansion Module
CC	combined cycle
CCS	carbon capture and storage
CentIv	Centralized Investments Module
CES	constant-elasticity of substitution
CGE	computable general equilibrium
CHP	combined heat and power
CO_2	carbon dioxide
DE	Germany
DistAB	Agent-Based Distributed Investments Module
DistEn	Distributed Energy scenario
DistIv	Optimization-Based Distributed Investments Module
DSM	demand-side management
DSO	distribution system operator
EIA	Energy Information Administration
ElCom	Swiss Federal Electricity Commission
eMark	Electricity Market Module
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European resource adequacy assessment
EU	European Union
FB	flow-based
FR	France
GDP	gross domestic product
GemEl	General Equilibrium Module for Electricity
GEP	generation expansion planning
GlobAmb	Global Ambition scenario
GW	gigawatt
HBS	household budget survey
IOT-Energy	differentiated input–output table for the energy sector
IRENA	International Renewable Energy Agency
IT	Italy
LHV	lower heating value
MW	megawatt
MWh	megawatt hour
NatTrds	National Trends scenario
NECP	National Energy and Climate Plans
NTC	net transfer capacity
PV	photovoltaic
PVB	photovoltaic battery
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
WACC	weighted average cost of capital

List of Figures

List of Tables

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

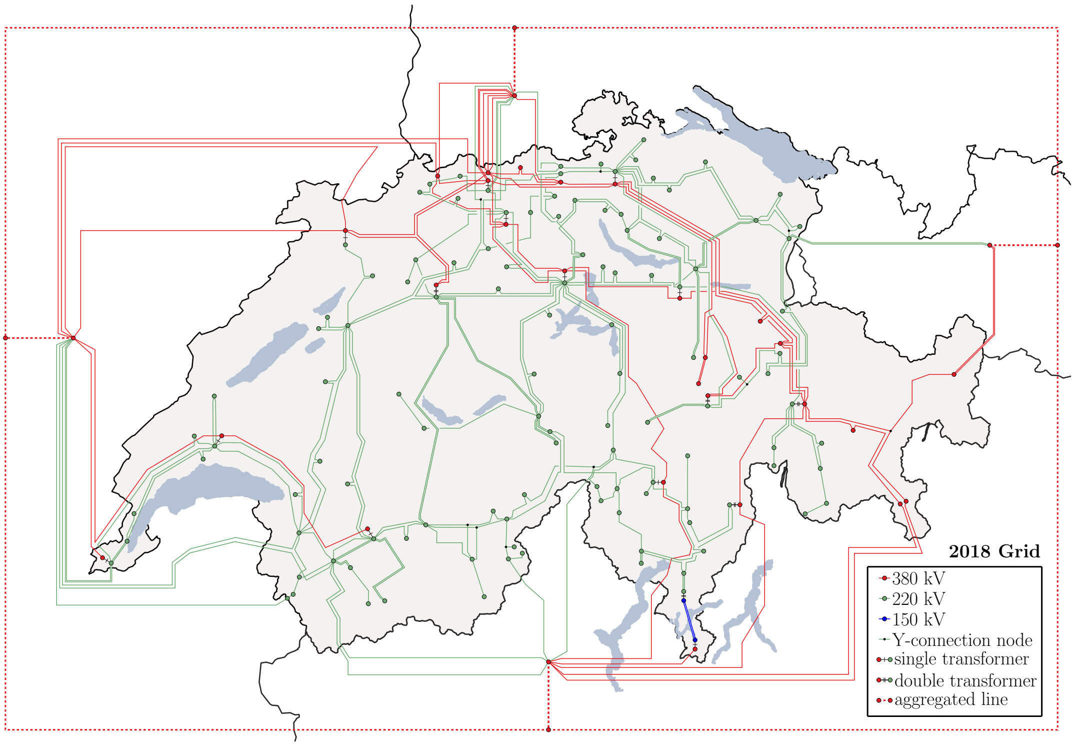
The Nexus-e framework includes a detailed representation of the Swiss transmission grid and an aggregated representation of the transmission grid of the four neighboring countries - Germany (DE), France (FR), Italy (IT), and Austria (AT), with data from Swissgrid [1] and the European Network of Transmission System Operators for Electricity (ENTSO-E) [2, 3]. Figure 1 shows the 2018 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.

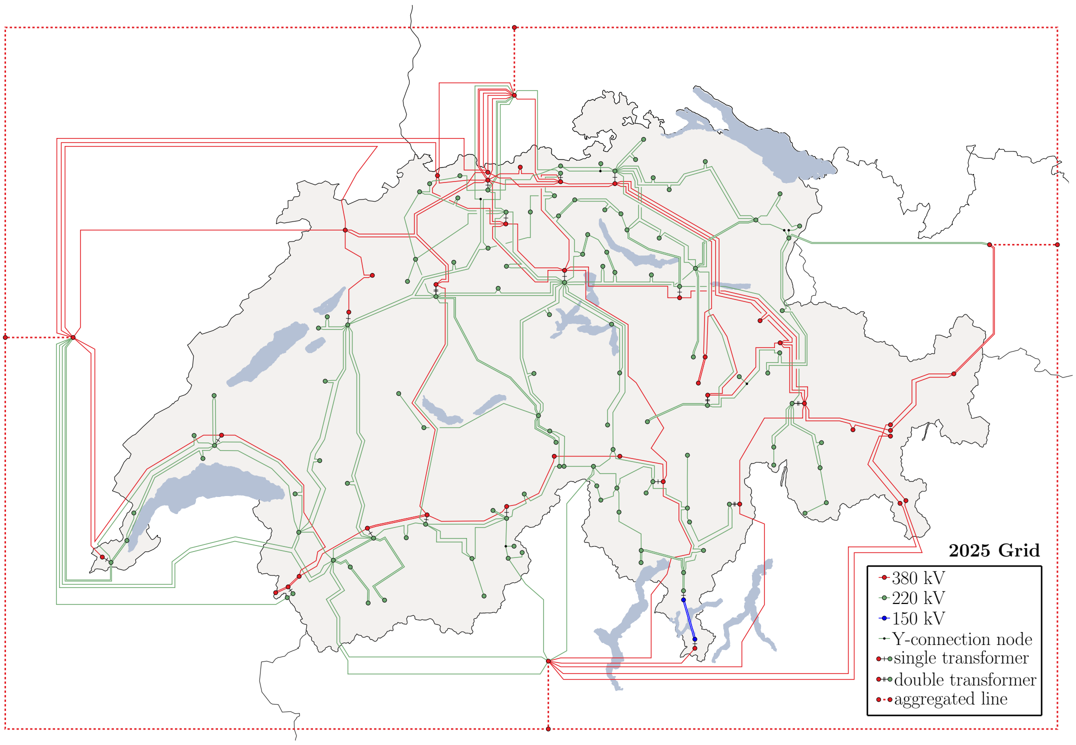
Table 1: Final branch reactances (x) of the aggregated lines used in all years in per unit (pu). Apparent power base is 100 MVA.

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) 2018 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], the ENTSO-E Transparency Platform for the forecasted transmission allocation of day-ahead transfer capacities [8], and the 2021 edition of the ENTSO-E European resource adequacy assessment (ERAA) [9]. Table 2 lists the NTC values utilized in all pre-2020 simulations, which utilize historical 2018 values from Swissgrid and the ENTSO-E Transparency Platform; Table 3 lists the NTC values utilized in all 2020 simulations, which utilize 2025 data from the ENTSO-E ERAA; Table 4 lists the NTC values utilized in all 2030-2050 simulations, which utilize 2030 data from the ENTSO-E ERAA.

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	1900
	AT	1200	—	4900	—	145
	DE	4000	4900	—	3000	—
	FR	1200	—	3000	—	1160
	IT	4240	337	—	3487	—

Table 3: NTC trade limitations between market zones in MW as modeled for all 2020 simulations.

		FROM				
		CH	**AT**	**DE**	**FR**	**IT**
TO	**CH**	—	1200	2600	3700	1910
	AT	1200	—	5400	—	500
	DE	4200	5400	—	3000	—
	FR	1400	—	3000	—	2160
	IT	4440	705	—	4350	—

Table 4: NTC trade limitations between market zones in MW as modeled for all 2030-2050 simulations.

		FROM				
		CH	**AT**	**DE**	**FR**	**IT**
TO	**CH**	—	1200	3800	3700	1910
	AT	1200	—	7500	—	1185
	DE	4400	7500	—	4800	—
	FR	1400	—	4800	—	2160
	IT	4440	1355	—	4350	—

The Network Security and Expansion Module (Cascades) uses module specific data for 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 [10]. Table 5 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 5: 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

In our model, Switzerland is divided into regions (e.g., municipalities, districts, or cantons), and each region is represented as a separated single-node distribution system (i.e., the distribution network is not modeled). While the evaluation of investments and operation of distributed generation resources does not currently include representing the limitations of the medium and low voltage electricity networks, it does include the limitation at the transformer connection between the distribution and transmission networks. Since distribution transformers are rarely fully loaded 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. We estimate the transformer capacity by the regional peak demand multiplied by a factor of 1.2[1].

[1] 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, storage volumes, and storage parameters (Section 2.1.2), the production profiles and placement for renewable energy source (RES) units (Section 2.1.3), the generator operating costs and fuel prices (Section 2.1.4), and the candidate unit data projections, capacities and placement (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) [11, 12, 13, 14, 15] and previous studies [16]. Additionally, operational parameters for the different technology types are taken from available literature [17] as well as previous works [18]. Table 6 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[2]. The generator parameters are also used when needed to represent the European generator fleet. These parameters are used in all 2020-2050 scenario simulations. The total capacities listed represent those existing in Switzerland in 2020, which we assume also remain in place until 2050. However, the listed photovoltaic (PV) units and capacities are only used to simulated a historical year, in this case 2020, and are represented at the centralized level (CentIv). For all future years, both the existing and newly built PV units are instead modeled within the distribution investment level (DistIv or DistAB). Since individual wind turbines and PV panels are not represented, the number of units listed instead reflects the number of transmission node locations where an aggregated wind or PV generator is placed. For the 2018 calibration simulation, the hydro pump unit at Nant de Drance is not included because this unit was commissioned in 2019 and the additional nuclear unit at Mühleberg is included since it was still operational in 2018. Additionally, for the 2018 calibration, a reduced amount of PV capacity is included to reflect the proper installations for that year. The biomass units represent the waste incineration facilities in Switzerland.

In addition to these existing hydro units, twenty-eight new hydro units, built in defined future years, are included that represent a mixture of pump, dam, and run of river (RoR) generators with a total additional capacity of 2.6 gigawatt (GW). Of these additions, 1.8 GW represent three new hydro pump units that are planned to be operational between 2029 and 2037 [19]. The rest are based on projects that have been previously or are now in planning stages [20]. These units are not candidates that the optimization could decided to build, but instead are assumed investments with a fixed commissioning date.

The minimum capacity indicates the lowest possible operating level and is given as a percentage of the generator's rated capacity. The thermal efficiency, given in megawatt hour (MWh) of electricity (MWh_e) per MWh of thermal energy[3] from fuel (MWh_{th}), represents the heat rate of the power plant and

[2] Some parameters listed are not utilized when the dispatch models are set to use only linear constraints (i.e., the minimum capacity and minimum up and down time can only be included when simulating the dispatch using a mixed-integer formulation).

[3] Values selected are defined based on the fuel's lower heating value (LHV)

Table 6: Operating parameters for Swiss generators. Number of units and total capacities are for the 2020-2050 simulations (assumptions for the nuclear phase-out are discussed in Section 7).

Technology Type	Number of Units	Total Capacity [MW]	Minimum Capacity [%]	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	0	-	-	-	-	-
Hydro Pump	22	4655	0	-	-	-	-	-
Hydro RoR	150	3957	0	-	-	-	-	-
Nuclear	4	3010	45	0.33	-	0.26	24	24
Gas CC	2	102	40	0.58*	0.40*	0.66	1	1
Gas SC	2	63	40	0.40	0.57	-	1	1
Biomass	22	229	38	0.45	-	0.54	8	6
Oil	1	25	40	0.39	0.50	1.67	2	2
Wind	6	75	0	-	-	-	-	-
PV	29	2975	0	-	-	-	-	-
Lignite	0	0	48	0.43	1.00	0.26	12	24
Coal	0	0	48	0.46	0.91	0.26	12	24
Gas CC CCS	0	0	40	0.53*	0.04*	0.66	1	1
Gas CC Syn	0	0	40	0.61*	0.00	0.66	1	1
Battery TSO	0	0	0	-	-	-	-	-

(*) values in future years are assumed to change, see details in Section 2.1.5

is used to quantify the fuel needed and associated fuel costs to produce any amount of electricity in MWh. Similarly, the carbon dioxide (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. 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 times 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 a few minutes). Depending on the model settings, the use of the minimum capacity and minimum up and down times are only utilized when unit commitment is enabled. Since we do not model the heating sector in Nexus-e, existing combined heat and power (CHP) units can either operate dispatchably, similar to normal gas-fired or oil-fired power generation units, or operate based on predefined hourly production profiles, similar to wind and PV. We do not include a 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 at the centralized level. While the operating parameters for these units are mostly the same as the values listed in Table 6, information regarding the number of units, total capacity by technology type, and changes in operating parameters can be found in Section 2.1.5. The gas combined cycle (CC) with carbon capture and storage (CCS) entry represents a post-combustion CO_2 capture facility with a reduced efficiency due to the use of process heat for the capture operation and only minimal remaining CO_2 emissions. The gas CC Syn entry represents a normal gas CC unit that consumes synthetically derived methane produced from methanation of hydrogen and CO_2. These two generator types also have modified costs, shown in Tables 10 and 13, to reflect the added investment and CO_2 disposal costs for CCS (Gas CC CCS) and the added cost to produce synthetic methane (Gas CC Syn).

For the outage periods of the Swiss nuclear reactors, we used data from [21, 22]. All Swiss nuclear reactors tend to 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 while the for the historical years (i.e., 2018) we set the outages based on when they actually occurred. Table 7 shows all modeled outages for each of the Swiss nuclear reactors in 2018 and the planed refueling outages for the reactors still operating in 2020 until the end of their lifetime. The lifetime of the Swiss reactors depends on the needs of a simulated scenario (see examples in Section 7).

Table 7: The outage schedules of Swiss nuclear reactors for the 2015 reference year and future scenario-years.

Reactor	2018	2020 - end of lifetime
Beznau 1	weeks 18-19 (2 weeks)	weeks 17-20 (4 weeks)
Beznau 2	weeks 24-27 (4 weeks)	weeks 32-35 (4 weeks)
Goesgen	weeks 23-25 (3 weeks)	weeks 22-25 (4 weeks)
Leibstadt	weeks 31-37 (7 weeks)	weeks 23-26 (4 weeks)
Muehleberg	weeks 30-36 (7 weeks)	not in operation

2.1.2 Hydro inflows, storage volumes and storage parameters

In addition to the parameters for hydro and other storage generators provided in Table 6, more input information is needed to represent the natural water inflows for all hydro generator types, the storage volumes of hydro dams and pumps, and the charging/discharging process of all storage types.

Original hourly inflow profiles are derived for both 2018 and 2020 from the known monthly production [23, 24] and weekly storage levels [25, 26] of the Swiss hydro storage units (dams and pumps); additional original profiles are derived using the known monthly production of Swiss hydro RoR units [23, 24]. 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 2018 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 pump unit reservoirs 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 with 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 [27, 11] 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 reservoirs 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. Even though not as complex as the hydro storages, battery storages also require a defined energy storage volume. To calculate this volume for any given size battery, we assume a constant ratio between a battery's energy volume and power capacity of 4-to-1. So, for the candidate batteries described later in Table 14 with a power rating of 100 MW, the energy storage volume is set to 400 MWh.

Additionally, to represent the losses in the charging and discharging processes of storage units the charging and discharging efficiencies must be set. In this work, we define these efficiencies as shown in Table 8 for Swiss and European generator types.

Table 8: Charging and discharging efficiencies (%) for Swiss and European storage generators.

Technology Type	Charging Efficiency [%]	Discharging Efficiency [%]
Hydro Dam	-	99
Hydro Pump	80	99
Battery TSO	96	96

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 [26]. We apply the actual initial energy volume (i.e., 49% and 72%) for the 2018 and 2020 simulations, respectively; alternatively, we apply a more general starting level (i.e., 55%) for all 2030-2050 simulations. The known energy volume at the end of 2018 and 2020 (i.e., 65% and 60%, respectively) are also applied, while we set the ending volume equal to the starting volume (55%) for the 2030-2050 simulations. For batteries, since they are not likely to operate in a seasonal cycle, their initial energy level is not as critical to their long-term operation. In this work, the starting and ending levels of batteries are set to 100%, so they are assumed to be full on the first hour of the year that is simulated.

2.1.3 Renewable production and placement

In addition to the parameters for wind and PV generators provided in Table 6, 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 [16] 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 [14] 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. In total, all existing wind capacities are assigned to six transmission node locations. 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 [16]. The scaling is done to ensure that the total wind generation matches the historical total for either the 2018 calibration year or the 2020 year [12]. Since no changes have been made to the installed Swiss wind capacities since 2020, the production profiles from these existing wind units are kept constant across all future modeled years.

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 [16]. 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 [28], 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 [16]. 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 [16]. The scaling is done to ensure that the total PV generation matches the historical total for the 2018 calibration year or the more recent 2020 historical year [12]. While these existing PV units are represented at the centralized level for historical year simulations (i.e., 2018 and 2020), all future-year simulations will instead include the existing PV at the distribution level along with the potential for newly built PV. This assumption is taken based on the validation of the distribution level module (DistIv).

Under development currently are the creation of the potentials, costs, and production profiles of other RES technologies including Alpine PV, Agrivoltaic, and Road-integrated PV.

2.1.4 Generator operating costs and fuel prices

To represent the variable operating costs of all Swiss generators (existing and candidates) data are utilized from recent BFE sponsored studies [29, 30, 31]. Additionally, data for battery storage units are taken from [32] and data for existing Swiss nuclear units are taken from the annual reports of these units over the past ten years [33, 34]. Table 9 lists the variable operation and maintenance (VOM) costs by technology type. The operating costs of biomass reflect current waste incineration subsidies [29, 30], which we expect to continue in the future. It is important to note that we assume that the VOM cost for each technology type is the same in the 2018 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 10 lists the fuel prices and CO_2 price for the 2018 reference year and the 2020-2050 scenario-years.

In all years, the Swiss prices for CO_2 are the same as the CO_2 prices applied to the neighboring country generators. The historical CO_2 prices for 2018 and 2020 are set based on data available from EEX [35]; while the future price projections are set based on a combination of the 2020 ENTSO-E ten-year network development plan (TYNDP) [36] and the European Investment Bank's Climate Strategy report [37]. Alternatively, all Swiss fuel prices are unique compared to the prices set for all other EU generators, shown in Table 22. The historical and future price projections for all standard fuels including for industry-size natural gas consumers (Gas-Ind) as well as oil, and biomass are set based on data provided by Swiss-specific studies [29, 30]. The price of uranium is assumed constant over time and is set based on data for existing Swiss nuclear units [33, 34]. The prices for biomass in Switzerland reflect

Table 9: VOM cost parameters for Swiss generators. VOM cost is used for the 2018 and 2020-2050 simulations.

Technology Type	VOM Cost [EUR/MWh]
Hydro Dam	10.0
Hydro Pump	8.2
Hydro RoR	9.1
Nuclear	20.8
Gas CC	2.0
Gas SC	11.0
Biomass	1.0
Oil	80.0
Wind	36.4
PV	27.3
Gas CC CCS	4.0
Gas CC Syn	2.0
Battery TSO	0.5

the current Swiss waste incineration subsidies [29, 30]. The price of category Gas-Ind-CCS is meant to represent the additional cost of CO_2 transport and disposal and has been increased appropriately based on another recent Swiss study [38]. Lastly, the prices of synthetically produced natural gas that would be imported to Switzerland (Gas-Syn-Imp) or that could be produced within Switzerland (Gas-Syn-Self) are set based on an additional Swiss study [39].

To better represent the seasonal variation of natural gas prices, data on European gas prices from Bloomberg New Energy Finance [40] for 2008-2021 are used to create monthly scaling factors. Monthly prices for each year are normalized by their annual average then a single yearly normalized profile is calculated by averaging across the 14 years of data for each month. These data are based on the monthly Dutch TTF price and the monthly factors are used to create a monthly price profile from the previously described annual average price for a given year. The quantified monthly gas prices are used by all Swiss generators that use the Gas-Ind and Gas-Ind-CCS fuel types (i.e., both synthetic gas fuel types continue to use only their quantified annual average price). The implementation of the monthly trend for natural gas prices enables the models to account for the seasonal variation in operating costs for gas generators and, more importantly, enhances the capabilities of the planned extensions of the Nexus-e modules to include a new model of the gas sector.

Using the VOM costs provided in Table 9 and combining the generator parameters in Table 6 with the fuel and CO_2 prices in Table 10, the total variable operating costs for Swiss generators of each technology type can be calculated for any of the years simulated. Table 11 shows these total variable operating costs for each of the existing technology types in each of the years simulated. Comparing the different Swiss technologies, biomass, batteries and hydro units (i.e., hydro pumps, RoRs, and dams) provide the lowest cost electricity, followed by other renewable (i.e., wind and PV) and nuclear units that also have quite low operating costs. Conventional generator types (gas CC, gas CC with CCS and gas SC) provide electricity at the next lowest cost, leaving the oil and synthetic gas-fired units as the most expensive generator types in Switzerland. From 2020 to 2050, while the RES, hydro, battery,

Table 10: The fuel prices (EUR/MWh_{th}) and CO_2 price (EUR/tonne) for Swiss generators for the 2018 calibration year and the 2020-2050 scenario-years.

Fuel [EUR/MWh_{th}] and CO_2 [EUR/tonne] Prices					
Fuel	**2018**	**2020**	**2030**	**2040**	**2050**
Gas-Ind	39.0	40.3	45.7	50.2	54.6
Gas-Ind-CCS	70.1	71.4	77.8	83.8	88.3
Gas-Syn-Imp	150.4	154.0	171.9	191.8	214.0
Gas-Syn-Self	185.6	190.0	212.0	236.6	264.1
Oil	39.5	47.0	58.4	62.9	65.6
Biomass	0.0	0.0	0.0	0.0	0.0
Uranium	4.23	4.23	4.23	4.23	4.23
CO2	15.6	24.3	35.0	80.0	166.0

and nuclear units have consistent total variable costs, the contributions from the fuel and CO_2 costs components result in steady increases to the Swiss gas and oil generator types until 2050. A trade-off can be seen occurring between the cost of gas CC and gas CC with CCS, which begins as much more expensive but by 2050 becomes almost the same as the gas CC because of the rising cost of emitting CO_2.

Table 11: 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	**2018**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	10.0	10.0	10.0	10.0	10.0
Hydro Pump*	8.2	8.2	8.2	8.2	8.2
Hydro RoR	9.1	9.1	9.1	9.1	9.1
Nuclear	33.6	33.6	33.6	33.6	33.6
Gas CC	75.4	81.0	94.6	120.0	161.4
Gas SC	117.4	125.5	145.3	182.1	242.2
Biomass	1.0	1.0	1.0	1.0	1.0
Oil	189.1	212.8	247.1	281.3	331.3
Wind	36.4	36.4	36.4	36.4	36.4
PV	27.3	27.3	27.3	27.3	27.3
Gas CC CCS	136.9	139.7	152.3	162.3	170.6
Gas CC Syn Imp	248.6	254.5	283.7	311.4	341.8
Gas CC Syn Self	304.2	311.5	347.6	378.6	419.2
Battery TSO*	0.5	0.5	0.5	0.5	0.5

(*) cost for consuming electricity during charging are not included in these values

2.1.5 Candidate generators

For centralized capacity expansion planning, a number of candidate units generator types are defined, including gas CC, biomass, and wind. While much of the operating parameters used for representing these candidate options is already shown in Table 6, Table 12 provides additional data on construction, decommissioning, and fixed costs taken from the indicated literature sources. While the values provided are for a single scenario-year (i.e., 2030), many of these costs reduce over time based on the associated assumptions from the listed literature sources. To annualize the upfront and end of life costs, the present value is first calculated for the year of commissioning using the appropriate construction time or plant lifetime and a discount rate of 5%. Construction times of zero years indicate the construction cost values are incurred at the time of commissioning. While we expect a non-zero fixed cost for nuclear units, the data sources utilized report all operating costs in per MWh of production and have therefore been included in the variable operating cost of nuclear [33, 34]. The annuity of the combined present value is also calculated, shown for 2030 in Table 13, again using the plant lifetime and the same discount rate.

Some of the operating parameters, shown in Table 6, change over time based on expected improvements in technology. Along with the projection of these operating parameters, similar projections for the investment and fixed operating costs are also needed for representing the total expense of constructing new generating units during different future years. Table 13 provides the resulting time-varying data, taken from recent Swiss studies [29, 30], used to represent all these candidate units. Additionally, data for battery storage units are taken from [32].

The number of candidates for a given generator type and the size of each candidate is customizable

Table 12: The construction, decommissioning, and fixed cost data for candidate units at the transmission system level in Switzerland in 2030.

Technology Type	Construction Cost [EUR/kW]	Decommissioning Cost [EUR/kW]	Fixed Cost [EUR/kW/yr]	Construction time [yr]	Ref
Biomass	1556	0	0	0	[30]
Wind	1778	0	41.3	0	[30]
Gas CC	879	0	21.5	0	[30]
Gas CC CCS	1542	0	38.5	0	[30]
Gas CC Syn	879	0	21.5	0	[30]
Battery TSO	2487	0	3.8	0	[32]
Nuclear	11106	40	0	10	[33, 34]

Table 13: The operating parameter and cost projections for candidate units at the transmission system level in Switzerland (2020–2050).

Technology Type	Parameter	2030	2040	2050
Biomass	Investment Cost [EUR/MW/yr]	124838	124838	124838
	FOM Cost [EUR/MW/yr]	0	0	0
Wind	Investment Cost [EUR/MW/yr]	142686	120653	110293
	FOM Cost [EUR/MW/yr]	41322	41322	41322
Gas CC	Investment Cost [EUR/MW/yr]	56378	55589	55589
	FOM Cost [EUR/MW/yr]	21212	20909	20909
	Thermal Efficiency [MWh_e/MWh_{th}]	0.61	0.62	0.63
	CO_2 Rate [ton/MWh_e]	0.329	0.323	0.320
Gas CC CCS	Investment Cost [EUR/MW/yr]	98957	97577	97577
	FOM Cost [EUR/MW/yr]	37878	37272	37272
	Thermal Efficiency [MWh_e/MWh_{th}]	0.53	0.54	0.55
	CO_2 Rate [ton/MWh_e]	0.044	0.039	0.037
Gas CC Syn	Investment Cost [EUR/MW/yr]	56378	55589	55589
	FOM Cost [EUR/MW/yr]	21212	20909	20909
	Thermal Efficiency [MWh_e/MWh_{th}]	0.61	0.62	0.63
	CO_2 Rate [ton/MWh_e]	0	0	0
Battery TSO	Investment Cost [EUR/MW/yr]	199567	199567	199567
	FOM Cost [EUR/MW/yr]	3790	3790	3790

based on the desired investigation. Table 14 provides the recommended options for power capacity, energy storage volume, number of units and lifetimes that are currently used in one or more of the Nexus-e studies.

Table 14: Capacity and quantity for candidate units at the transmission system level in Switzerland (2020–2050)

Technology Type	Power Capacity [MW]	Storage Volume [MWh]	Number of Units	Total Capacity [MW]	Lifetime [yrs]
Biomass	20	-	12	240	20
Wind	-	-	7	1960	20
Gas CC	200	-	0	0	30
Gas CC CCS	500	-	11	5500	30
Gas CC Syn	500	-	11	5500	30
Battery TSO	100	400	41	4100	20
Nuclear	1600	-	5	8000	60

We restrict the total candidate capacity of biomass to account for limited resource availability [29, 30]. The costs of biomass reflect current waste incineration subsidies [29, 30], 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 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 [30]. Wind candidates are included that in total produce around 4.0 TWh/a, which is also consistent with the Swiss wind energy concept [41]. The number of units provided for wind indicates the number of transmission node locations used to split the total candidate wind capacity. Similar to the geographical assignment of existing Swiss wind units, described in Section 2.1.3, the placement of candidate wind units is based on the seven locations with the highest wind potential determined in AFEM [16]. 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.

The power capacity, storage volume and number of units for the gas, battery, and nuclear units are adjustable depending on the needs of the study; however, these units do not have a similar upper limit based on resource availability like that of wind and biomass. The quantities for the size and number of units shown are one example of the candidates recently utilized by the Nexus-e team. Locations for the gas units are selected based on the recommendations of a recent study from Swiss Federal Electricity Commission (ElCom) [42]. No investment subsidy is included to offset the investment costs for new gas-fired units. Locations for the nuclear candidate units are selected based on projects that were cancelled before beginning construction [43, 44] and other previously approved locations for new nuclear units in Switzerland [45].

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 all current projects, 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 [29, 30]. 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. Lastly, 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 2020 ENTSO-E TYNDP [36], as shown in Section 2.2.

Under development currently are the creation of the potentials, costs, and production profiles of other RES technologies including Alpine PV, Agrivoltaic, and Road-integrated PV. These capacities will be utilized as potential candidates for investment at the centralized level in future studies.

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, storage volumes, and storage parameters (Section 2.2.2), the production profiles for RES units (Section 2.2.3), and the generator operating costs and fuel prices (Section 2.2.4).

All generators in each of 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 2020 ENTSO-E TYNDP scenarios [36]. Additionally, the EU generator parameters (VOM costs, CO_2 rates, and efficiencies) are based on the information provided in the newest Energy Information Administration (EIA) study [46] on “Projected Costs of Generating Electricity” as well as in the “Current and Prospective Costs of Electricity Generation until 2050” prepared and published by the DIW Berlin [17]. This second document comprises data from different sources, and those that we used most frequently are:

- IEA, NEA, & OECD, Projected Costs of Generating Electricity [47, 48]
- IPCC, Renewable Energy Sources and Climate Change Mitigation [49, 50]
- IRENA, Biomass for Power Generation [51]

2.2.1 Capacities and operating parameters

For the 2018 calibration year and the 2020 year, the generator capacities are defined using historical data from the ENTSO-E Transparency Platform [52] and the ENTSO-E annual Statistical Factsheet [53]. Since the data available from these ENTSO-E sources is sometimes not detailed enough (i.e., does not split gas CC and gas SC) or even incorrect (i.e., drastically under reports the Italian PV capacity in 2020), we corroborate and sometimes modify the historical capacities based on other data sources. The Italian PV capacity is corrected based on a report from International Renewable Energy Agency (IRENA) [54]. The splitting of gas CC and gas SC for Italy is done using data available from TERNA [55]. Similarly, the split of gas CC and gas SC for Germany, France, and Austria are done using data available from [56]. Additionally, values for installed battery capacities are taken from [57] and [58].

In the 2030-2050 scenarios, the generator capacities are instead defined based on the installed capacity projections from the 2020 ENTSO-E TYNDP report [36]. Within their report, ENTSO-E provides data for three scenarios: the National Trends scenario (NatTrds), the Global Ambition scenario (GlobAmb), and the Distributed Energy scenario (DistEn). The NatTrds scenario reflects the most recent EU National Energy and Climate Planss (NECPs) to meet the current EU energy strategy targets. Alternatively, both DistEn and GlobAmb scenarios aim at reaching the 1.5 ℃ target of the Paris Agreement following the carbon budget approach and aim to reduce the EU-28 emissions to net-zero by 2050. DistEn embraces a decentralized approach to the energy transition whereas GlobAmb looks at a future where development is led through centralized generation. While the data from all three scenarios have been setup, in the current Nexus-e investigations, data from the GlobAmb scenario tend to be utilized. Again because some data available from the TYNDP is not detailed enough, we make some adjustments, including:

- assume the category 'Other RES' is biomass,
- split the category 'Other Non-RES' into a mixture of gas CC, gas SC and oil depending on the country,
- adjust the capacities of Italian hydro dam and RoR to align with the 2020 data from the ENTSO-E Transparency Platform [52].

While the ENTSO-E TYNDP creates their top-down scenarios (GlobAmb and DistEn) to reach a net-zero criteria in 2050, they only provide data for these projections as well as for the NatTrds scenario until 2040. To represent capacities in 2050, we therefore create our own projection keeping in mind the developments in the TYNDP scenarios between 2030-2040. We make the following assumptions to create our projected 2050 capacities:

- Hydro dam, pump, and RoR along with any remaining nuclear, gas, biomass, and oil capacities remain constant between 2040 and 2050.
- Wind and PV capacities increase with similar trajectories as the increase between 2030-2040. We apply the same assumptions utilized within the TYNDP for the minimum investments to ensure that our 2050 projections fulfill the scenario storylines. Table 15 lists the assumed 2040-2050 capacity growth as a percentage of the 2030-2040 growth for each scenario and generator type.
- For batteries, we use data available in [57] to set the installed capacities in 2050 for both the DistEn and NatTrds scenarios. Additionally, for the GlobAmb scenario, we maintain the ratio of the capacities in 2040 between the GlobAmb and DistEn scenarios to set the 2050 battery capacities.

Table 15: Assumed 2040-2050 RES capacity growth as a percentage of the 2030-2040 capacity growth.

Technology Type	**National Trends**	**Global Ambition**	**Distributed Energy**
Wind-On	50	80	50
Wind-Off	80	80	50
PV	65	50	80

Tables 16, 17, 18, and 19 provide the values for the capacities by technology type over the simulated years for each of the four neighboring countries based on the GlobAmb scenario of the TYNDP 2020. As part of the calibration process, some of the capacities listed have already 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=85% & FR=73%; for Biomass: DE=65%). The generator capacities of each surrounding country are placed at the main country node (not at the border node).

The operating parameters for the aggregate generators of all the neighboring countries are the same as those shown for the Swiss generators in Table 6; 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 16: German generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [52, 53, 36].

Germany - Installed Capacity [MW]					
Technology Type	**2018**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	1440	1298	1297	1297	1297
Hydro Pump	8918	9422	10 037	10 037	10 037
Hydro RoR	3860	3970	4036	4036	4036
Nuclear	8089	6897	0	0	0
Lignite	21 275	21 067	7677	0	0
Coal	25 035	22 458	6603	0	0
Gas CC	19 764	20 546	28 241	31 715	31 715
Gas SC	11 597	11 166	6168	5878	5878
Biomass	4807	5192	4313	3403	3403
Oil	4247	4373	4373	4373	4373
Wind-On	51 633	53 184	78 801	95 401	108 681
Wind-Off	5051	7504	20 000	23 228	25 810
PV	42 804	48 206	83 877	105 032	115 610
Gas CC CCS	0	0	0	0	0
Battery TSO	123	962	1596	3246	4985
Battery DSO	185	1442	2394	4868	7478

Table 17: French generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [52, 53, 36].

France - Installed Capacity [MW]					
Technology Type	**2018**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	8578	7188	8200	8200	8200
Hydro Pump	5020	4656	3500	3500	3500
Hydro RoR	11 222	9759	13 600	13 600	13 600
Nuclear	45 454	45 454	40 783	26 812	26 812
Coal	3972	2977	0	0	0
Gas CC	11 446	11 859	11 213	11 213	11 213
Gas SC	366	379	636	392	392
Biomass	1840	1578	2549	2549	2549
Oil	6263	2874	1873	1873	1873
Wind-On	12 518	16 578	32 455	43 855	52 975
Wind-Off	0	14	4920	12 425	18 429
PV	7170	9438	29 462	41 186	47 048
Gas CC CCS	0	0	0	0	0
Battery TSO	0	506	1234	2849	5981
Battery DSO	0	758	1850	4273	8972

Table 18: Italian generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [52, 53, 36].

Italy - Installed Capacity [MW]					
Technology Type	**2018**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	4733	4459	4459	4459	4459
Hydro Pump	6453	7276	11 899	11 899	11 899
Hydro RoR	10 826	10 441	10 441	10 441	10 441
Coal	8489	9008	0	0	0
Gas CC	40 710	40 556	38 671	38 671	38 671
Gas SC	3738	3734	11 382	11 382	11 382
Biomass	1354	1549	4932	4932	4932
Oil	2475	1493	0	0	0
Wind-On	9261	10 224	19 048	23 808	27 616
Wind-Off	0	0	600	644	679
PV	20 107	21 600	30 819	54 391	66 177
Gas CC CCS	0	0	0	0	0
Battery TSO	23	100	200	603	1160
Battery DSO	34	150	299	904	1740

Table 19: Austrian generators are represented by single units aggregated by technology type. Capacities change over time based on data provided in [52, 53, 36].

Austria - Installed Capacity [MW]					
Technology Type	**2018**	**2020**	**2030**	**2040**	**2050**
Hydro Dam	2985	2436	2434	2434	2434
Hydro Pump	3401	3120	5697	6637	6637
Hydro RoR	5605	5724	6142	6292	6292
Coal	598	246	0	0	0
Gas CC	3217	2891	3777	2336	2336
Gas SC	1251	1124	590	240	240
Biomass	491	497	599	599	599
Oil	178	178	168	0	0
Wind-On	2887	3133	10 000	15 000	19 000
Wind-Off	0	0	0	0	0
PV	1193	1333	6420	9256	10 674
Gas CC CCS	0	0	0	0	0
Battery TSO	12	18	214	494	915
Battery DSO	18	28	320	740	1372

2.2.2 Hydro inflows, storage volumes and storage parameters

In addition to the installed capacities of hydro generators provided in Tables 16-19, more input information is needed to represent the natural water inflows for all hydro generator types, the storage volumes of hydro dams and pumps, and the charging/discharging process of all storage types. 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. Utilizing the inflow profiles created for the Swiss hydro generator types (see Section 2.1.2) along with the known 2018 annual production from these units in each neighboring country from the ENTSO-E Transparency Platform [59], the Swiss profiles are scaled to achieve these desired production levels.

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 hydro dam as well as hydro pump units. Each dam reservoir is sized to be able to continuously discharge for 863 hours (the same as the Swiss hydro dam units), 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. Battery storages also require a defined energy storage volume. To calculate this volume for any given battery capacity in one of the neighboring EU countries, we assume a constant ratio between a battery's energy volume and power capacity of 2.7-to-1. So, for the battery capacities listed in Tables 16-19, the energy storage volume is always calculated as 2.7 times the installed capacity.

Additionally, to represent the losses in the charging and discharging processes of storage units the charging and discharging efficiencies must be set. In this work, we define these efficiencies the same for each storage type, regardless of country location. Table 8 previously provided the values for these efficiencies.

The starting and ending levels for all hydro dam and pump units in the neighboring countries are currently defined as being identical to that of the Swiss hydro dam and pump units in a given year. We apply the actual initial energy volume (i.e., 49% and 72%) for the 2018 and 2020 simulations, respectively; alternatively, we apply a more general starting level (i.e., 55%) for all 2030-2050 simulations. The known energy volume at the end of 2018 and 2020 (i.e., 65% and 60%, respectively) are also applied, while we set the ending volume equal to the starting volume (55%) for the 2030-2050 simulations. Again, similar to the batteries in Switzerland, the starting and ending levels of batteries in the neighboring countries are set to 100%, so they are assumed to be full on the first hour of the year being simulated.

2.2.3 Renewable production

In addition to the capacities for wind and PV generators provided in Tables 16-19, more input information is needed to represent their hourly production profiles. Creating these profiles relies heavily on data available from the ENTSO-E Transparency Platform [59].

The hourly production profiles for the onshore wind and PV units are first set based on 2018 data available from the ENTSO-E for each country in 2018 [59]. The offshore wind production profiles are instead based on data available from the Renewables Ninja online tool [60, 61, 62]. These 2018 profiles are normalized and scaled for all other years 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 2020 historical year, the annual totals for each country are similarly obtained from the ENTSO-E Transparency Platform [59]. For the 2030-2050 scenario-years, the ENTSO-E TYNDP [36] scenario data are the only source used to set the annual production totals for wind and PV in each of the neighboring countries. The resulting production profiles are created for each of the TYNDP scenarios (the NatTrds, the GlobAmb, and the DistEn) for a given weather year (available data are for weather years 1982, 1984, and 2007). Table 20 lists the annual totals for wind and PV in each year for the neighboring countries. In this case the data provided for 2030-2050 are for the GlobAmb scenario using the weather year 2007. Once scaled, the hourly profiles are applied in the Nexus-e platform for the corresponding neighboring country in the appropriate year.

Table 20: The annual wind and PV production (TWh) of the units located in the Swiss neighboring countries for each simulated year.

RES Type - Year	Austria	France	Germany	Italy
Wind-On - 2018	6.4	26.8	89.5	17.3
Wind-On - 2020	7.2	38.3	103.1	18.6
Wind-On - 2030	25.8	82.7	184.1	47.0
Wind-On - 2040	40.0	136.6	263.6	60.9
Wind-On - 2050	50.6	165.1	300.3	70.6
Wind-Off - 2018	0.0	0.0	19.1	0.0
Wind-Off - 2020	0.0	0.0	26.9	0.0
Wind-Off - 2030	0.0	19.9	84.8	1.6
Wind-Off - 2040	0.0	50.2	77.8	1.6
Wind-Off - 2050	0.0	74.5	86.5	1.6
PV - 2018	1.4	9.7	41.2	22.9
PV - 2020	0.9	12.5	45.8	26.1
PV - 2030	7.6	36.0	82.0	42.1
PV - 2040	10.1	49.7	94.1	71.9
PV - 2050	11.6	56.8	103.6	87.4

2.2.4 Generator operating costs and fuel prices

To represent the variable operating costs of all EU generators, we use data from the newest EIA study [46] as well as the comprehensive review done by [17]. Additionally, data for battery storage units are taken from [32]. Table 21 lists these costs 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[4]. It is important to note that we assume that the VOM cost for each technology type is the same in the 2018 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 22 lists the fuel prices and CO_2 price for the 2018 reference year and the 2020-2050 scenario-years.

[4]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 21: The VOM costs (EUR/MWh) of the units located in the Swiss neighboring countries.

Technology / Country	Austria	France	Germany	Italy
Hydro Dam	15.0	15.0	15.0	15.0
Hydro Pump	6.7	6.7	6.7	6.7
Hydro RoR	7.1	7.1	7.1	7.1
Nuclear	-	10.8	10.8	-
Lignite	-	-	20.0	-
Coal	16.7	16.7	5.0	16.7
Gas CC	5.0	5.0	5.0	18.8
Gas SC	8.3	8.3	8.3	8.3
Biomass	1.0	1.0	1.0	1.0
Oil	80.0	80.0	80.0	80.0
Wind-On	12.9	12.9	12.9	12.9
Wind-Off	-	18.8	18.8	18.8
PV	17.9	17.9	17.9	17.9
Gas CC CCS	10.0	10.0	10.0	10.0
Gas CC Syn	5.0	5.0	5.0	18.8
Battery TSO	0.5	0.5	0.5	0.5
Battery DSO	0.5	0.5	0.5	0.5

Table 22: The fuel prices (EUR/MWh$_{th}$) and CO_2 price (EUR/ton) for the neighboring country generators for the 2018 calibration year and the 2020-2050 scenario-years.

Fuel [EUR/MWh$_{th}$] and CO_2 [EUR/tonne] Prices					
Fuel	**2015**	**2020**	**2030**	**2040**	**2050**
Gas	23.0	20.2	24.9	26.3	27.8
Gas-CCS	54.1	51.2	56.9	60.0	61.4
Gas-Syn	84.4	86.4	96.4	107.6	120.1
Coal	12.8	10.8	15.5	24.9	34.3
Lignite	4.0	4.0	4.0	4.0	4.0
Oil	39.0	46.4	73.8	79.9	86.0
Biomass	3.2	3.2	3.2	3.2	3.2
Uranium	1.7	1.7	1.7	1.7	1.7
CO2	15.6	24.3	35.0	80.0	166.0

In all years, the European prices for CO_2 are the same as the CO_2 prices applied in Switzerland and described in Section 2.1.4. Alternatively, all EU fuel prices are unique compared to the prices set for Swiss generators, shown previously in Table 10. The historical (2018 and 2020) prices for gas and coal are taken from the EU Commission's quarterly report on electricity markets [63], while the 2030-2050 prices for these fuels are based on data from the ENTSO-E TYNDP [36]. The prices of lignite and uranium, which are constant across all years, along with the prices of oil are also taken from the TYNDP [36]. The prices of biomass were originally set based on data from the Heat Roadmap Europe report on future fuel prices [64], but were later adjusted as part of the calibration process. The price of category Gas-CCS is meant to represent the additional cost of CO_2 transport and disposal and has been increased appropriately based on a recent Swiss study [38]. Lastly, the price of synthetically produced natural gas (Gas-Syn) is set based on a recent study of the costs of producing methane from renewable hydrogen [65].

Similar to the Swiss fuel prices, a monthly scaling profile is applied to both the Gas and Gas-CCS fuel prices to better represent the seasonal variation of natural gas prices. The monthly scaling factors are calculated based on monthly historical data on the Dutch TTF gas prices from Bloomberg New Energy Finance [40] for 2008-2021. The implementation of the monthly trend for natural gas prices enables the models to account for the seasonal variation in operating costs for gas generators and, more importantly, enhances the capabilities of the planned extensions of the Nexus-e modules to include a new model of the gas sector.

Using the VOM costs provided in Table 21 and combining the generator parameters in Table 6 with the fuel and CO_2 prices in Table 22, 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 23 and 24 below provide demonstrations of these total variable operating costs for 2020 and 2050, respectively.

Table 23: The total variable costs (EUR/MWh) for the units located in the Swiss neighboring countries in the 2020 scenario-year.

Technology / Country	**Austria**	**France**	**Germany**	**Italy**
Hydro Dam	15.0	15.0	15.0	15.0
Hydro Pump*	6.7	6.7	6.7	6.7
Hydro RoR	7.1	7.1	7.1	7.1
Nuclear	-	16.0	16.0	-
Lignite	-	53.5	-	-
Coal	62.3	62.3	50.6	62.3
Gas CC	47.6	47.6	47.6	61.4
Gas SC	76.2	76.2	76.2	76.2
Biomass	8.1	8.1	8.1	8.1
Oil	211.2	211.2	211.2	211.2
Wind-On	12.9	12.9	12.9	12.9
Wind-Off	-	18.8	18.8	18.8
PV	17.9	17.9	17.9	17.9
Gas CC CCS	0.0	0.0	0.0	0.0
Gas CC Syn	0.0	0.0	0.0	0.0
Battery TSO*	0.5	0.5	0.5	0.5
Battery DSO*	0.5	0.5	0.5	0.5

(*) cost for consuming electricity during charging are not included in these values

Table 24: The total variable costs (EUR/MWh) for the units located in the Swiss neighboring countries in the 2050 scenario-year.

Technology / Country	Austria	France	Germany	Italy
Hydro Dam	15.0	15.0	15.0	15.0
Hydro Pump*	6.7	6.7	6.7	6.7
Hydro RoR	7.1	7.1	7.1	7.1
Nuclear	-	16.0	16.0	-
Lignite	-	195.2	-	-
Coal	242.3	242.3	230.6	242.3
Gas CC	112.7	112.7	112.7	126.5
Gas SC	190.2	190.2	190.2	190.2
Biomass	8.1	8.1	8.1	8.1
Oil	383.6	383.6	383.6	383.6
Wind-On	12.9	12.9	12.9	12.9
Wind-Off	-	18.8	18.8	18.8
PV	17.9	17.9	17.9	17.9
Gas CC CCS	0.0	0.0	0.0	0.0
Gas CC Syn	0.0	0.0	0.0	0.0
Battery TSO*	0.5	0.5	0.5	0.5
Battery DSO*	0.5	0.5	0.5	0.5

(*) cost for consuming electricity during charging are not included in these values

2.3 Swiss distributed generators

In this section, the necessary data and sources are presented for the Swiss generators located at the distribution level of the energy system. These data include: the capacities, operating parameters, and current costs (Section 2.3.1), additional details on the selection of future cost developments (Section 2.3.2), and the modeled potentials for rooftop PV investments and clustering method (Section 2.3.3). While these data were originally setup for use in the Optimization-Based Distributed Investments Module (DistIv) module of Nexus-e, much of the same data are also utilized the more recent agent-based distributed investment module (DistAB). Based on the desired outcomes of the study, the DistIv and Agent-Based Distributed Investments Module (DistAB) modules can be used interchangeably to investigate the investments and operation of capacities in the distribution system.

2.3.1 Capacities, operating parameters and current costs

The modeled distribution system consists of six types of distributed energy technologies, namely PV, photovoltaic battery (PVB)[5], biomass-wood, biomass-manure, CHP, and grid-battery. The grid-batteries charge during low electricity price periods and discharge during high electricity price periods to perform inter-temporal market arbitrage. Alternatively, the PVBs have no direct connection to the grid and in general charge (or discharge) when the demand of the PV investor is lower (or higher) than their PV generation. Five PV categories (i.e., 0-6 kWp, 6-10 kWp, 10-30 kWp, 30-100 kWp, >100 kWp) are considered with the minimum and maximum capacity limited to 2 kWp and 50 MWp, which covers most of the potential investments and also corresponds to the range of PV units that could apply for the one-time investment subsidies in Switzerland [66]. The decision on the investment for each rooftop PV unit always includes the optional decision to also invest in the PVB, so even though they are presented in the data below with separated parameters, the PV and PVB are modeled as a combined system.

Tables 25 and 26 provide an overview of key parameters for these technologies, using 2018 as the reference year for the cost values. For most of the distributed generation technologies, we use the data from [29, 30]. For the PVB, assumed battery costs vary greatly between different studies ranging from 200 EUR/kWh to 1883 USD/kWh [67, 68, 69, 70]. The PVB costs selected for use in the Nexus-e simulations are based on [71] and are broken down into costs associated with the power rating (per kW) and with the storage size (per kWh). For the grid-battery, we use cost information from the Tesla Powerpack [72].

The investment decisions for the PV and PVB components consider continuous sizing. For the PV, this means that a given rooftop can invest in combinations of different sized PV units as long as the total rooftop area is not exceeded. And within each of the PV categories, the investment can be sized to any capacity desired (i.e., a 7.5 kW PV unit could be built based on the cost of the 6-10 kW PV size category). For the PVB, by allowing continuous sizing of both the power and energy ratings combined with representing the investment cost as a combination of both a per power (EUR/kW) and a per energy (EUR/kWh) component, the battery can be built with the optimal power-to-energy ratio for the individual customer.

The lifetime of the PVB is assumed to be the same as the lifetime of PV, i.e. 30 years. Since the lifetime of a battery unit is in general shorter than 30 years, a battery replacement is assumed and the potential remaining value of the last reinvested battery by the end of the PVB system lifetime is also calculated. To reflect the desire of PV investors to reduce the risk of their investment, we set the amortization period of the PV units to be 10 years, which is much shorter than their total lifetime of 30 years. However, for all other technologies, the economic decision to invest is based on an amortization

[5] This unit is a battery that connects to and charges from a PV unit but the cost and other data provided are only for the battery and do not include the costs of the PV.

Table 25: Parameters for distributed Swiss investment candidates.

Type	Size	Investment cost (€/kW)	Variable operation cost (€-cent/kWh)	Fixed operation cost (€/kW/year)	Fuel cost (€-cent/kWh)	Emissions (eq. g/kWh)	Lifetime (years)	Amortization period (years)
PV	0-6 kWe	2,902	2.7	0	0	0	30	10
PV	6-10 kWe	2'767	2.7	0	0	0	30	10
PV	10-30 kWe	2'295	2.7	0	0	0	30	10
PV	30-100 kWe	1'570	2.7	0	0	0	30	10
PV	>100 kWe	1'005	1.8	0	0	0	30	10
PV-battery	no limit kWe no limit kWh	423 500*	0.2	6.2	0	0	13	30
Biomass wood	50 kWe	6'061	0	318	7.07	35	10	10
Biomass manure	25 kWe	10'284	0	544	17.30	30	15	15
CHP	10 kWe	4'127	3.5	0	27.11	611	20	20
Grid-battery	50 kWe 100 kWh	638*	0	2.5% of InvCost	0	0	20	20

(*) this investment cost is based on the storage size (EUR/kWh)

Table 26: Additional parameters of the PV and PVB system.

Category	Parameter	Adopted value	Source
PV	Module efficiency	17%	[30]
	Inverter efficiency	98%	[30]
	Performance ratio	80%	[30]
	Degradation rate	0.5% per year	[30]
	Area requirement	6 m^2/kWp	[30]
	Lifetime	30 years	[30]
	Amortization period	10 years	n/a
Battery	Depth of discharge	100%	[71]
	Charging/discharging efficiency	93%	[71]
	Inverter efficiency	100%	n/a
	Self-discharge	0%	[71]
	Lifetime	13 years	[71]
	Amortization period	30 years	n/a
PVB system	Degradation rate	0.5% per year	[30, 73]

period equal to the technology lifetimes. For the PVB, since the reinvestment and residual is included to result in a lifetime equal to the PV unit, the amortization period used is the full 30 years. The weighted average cost of capital (WACC) is set to be 4% [74].

In the investment decision for CHP units, we include their CO_2 emissions and the associated costs; 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 from CHPs and, instead, assume that CHP owners sell the electricity at the wholesale market price since we assume that larger investors install CHP units and not individual households. For biomass from wood and manure as well as CHP units, we assume a capacity factor of 0.54, 0.78, and 0.28 [30], respectively. These dispatchable generation units have a ramp rate limit of 25% of their maximum capacity per hour.

Additionally, 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%) [75]. Details of the network fees, PV injection tariffs and the wholesale-to-retail price markups that are used to quantify the profitability of PV investments can be found in Section 5.

2.3.2 Selecting PV and battery cost developments

We include decreasing investment and operation costs for all five PV categories and both battery categories until 2050, while all other parameters remain constant. Future investment and operational costs for PV are estimated using projections from [29, 30], while future costs for PVB and grid-battery are estimated using projections from [71]. Data for missing years are estimated using an interpolation or extrapolation method. Table 27 presents the assumptions on the development of the PV and storage investment and operation costs, presented as a percentage of the 2018 reference year costs. Tables 28 and 29 provide the resulting values of the various investment and operating costs over time for PV and PVB units quantified based on the reference 2018 costs and the projected reduction in costs over time.

Table 27: Assumed projections for future investment and operational costs of distributed units.

(a) Investment costs

Category	2018	2020	2030	2040	2050
PV 0-6 kWp	100%	86%	71%	61%	57%
PV 6-10 kWp	100%	87%	71%	57%	44%
PV 10-30 kWp	100%	84%	69%	57%	48%
PV 30-100 kWp	100%	81%	66%	57%	52%
PV >100 kWp	100%	81%	66%	57%	52%
PV-battery	73%	55%	23%	16%	14%
Grid-connected battery	100%	100%	72%	53%	39%

(b) Operational costs

Category	2018	2020	2030	2040	2050
PV 0-6 kWp	100%	95%	78%	68%	64%
PV 6-10 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%
PV-battery	73%	55%	23%	16%	14%
Grid-connected battery	100%	100%	72%	53%	39%

2.3.3 Rooftop PV potential and data clustering

We focus on rooftop solar for residential buildings and simulate each potential rooftop based on the Sonnendach dataset [76], which analyzes the solar generation potential for Switzerland by accounting for the roof area, orientation, tilt, utilization type and region. The high level of detail in this dataset thus enables a high level of granularity in our simulation results. For all PV categories, we assume that the area required for 1 kWe of PV is 6 square-meters. According to [76], only buildings with roof areas greater than 10 m^2 and an annual solar irradiation higher than 1000 kWh/m^2 should be considered. The availability factors of the rooftops, which reduce the effective rooftop area, range between 42% and 80%

Table 28: Baseline PV cost scenario for 2018-2050 [29, 30].

		2018	2020	2030	2040	2050
PV investment cost (€/kWp)	**0-6 kWp**	2,902	2’496	2’060	1’770	1’654
	6-10 kWp	2,767	2’393	1’964	1’578	1’204
	10-30 kWp	2’295	1’916	1’572	1’308	1’102
	30-100 kWp	1’570	1’272	1’036	895	816
	>100 kWp	1’005	814	664	573	523
PV operational cost (€-cent/kWh)	**0-6 kWp**	2.7	2.6	2.1	1.9	1.7
	6-10 kWp	2.7	2.6	2.1	1.8	1.7
	10-30 kWp	2.7	2.6	2.1	1.8	1.7
	30-100 kWp	2.7	2.6	2.1	1.8	1.7
	>100 kWp	1.8	1.7	1.4	1.2	1.2

Table 29: Baseline PV-battery cost scenario for 2018-2050 [71].

		2018	2020	2030	2040	2050
Investment cost (energy-related)	**€/kWh**	500	377	158	110	96
Investment cost (power-related)	**€/kW**	423	319	133	93	81
Operation cost (energy-related)	**€/MWh**	0.2	1.41	0.59	0.41	0.36
Operation cost (power-related)	**€/kW-year**	6.2	4.70	1.97	1.37	1.20

depending on building types, roof sizes and tilt. This range accounts for the possible unavailability of the roof areas due to factors such as obstructions, windows and shadings (for details see page 7 of [76]). After accounting for these factors, the theoretically available rooftop area is reduced from 630 km^2 to 304 km^2 (i.e. 105 GW to 51 GW assuming 6 m^2/kWp). The data are further processed by focusing on detached buildings (i.e. Einzelhaus) with warm water consumption that account for around 94% of the potential solar generations and exclude potentials from bridges, high buildings, buildings under construction, etc. Finally, the total potential rooftop area modeled in this work equals 224 km^2 (i.e. 37 GW), which corresponds to 3’795’145 rooftop data entries.

PV potentials in Switzerland are shown in Figure 2 and Figure 3. First, Figure 2 illustrates the potentials in relation to the cantonal location and rooftop irradiation level. While some cantons like Valais and Ticinio have more rooftops with higher annual irradiation (these have small but non-zero numbers at higher radiation levels), the most populated cantons like Zurich and Bern have many more rooftops and therefore greater overall potential for PV investments. Not all cantons are shown in Figure 2 because PV potentials of cantons without transmission nodes are aggregated into the nearby cantons. Second, Figure 3 shows the potential in relation to the same irradiation levels but now also in relation to the PV size categories[6]. Since these size categories are based on the sizes of the rooftops, it is evident that

[6]The smallest PV category shown is now separated into two categories in our models.

the majority of rooftops in Switzerland are grouped in the smallest two PV categories while few rooftops are big enough to fit the largest size PV installation.

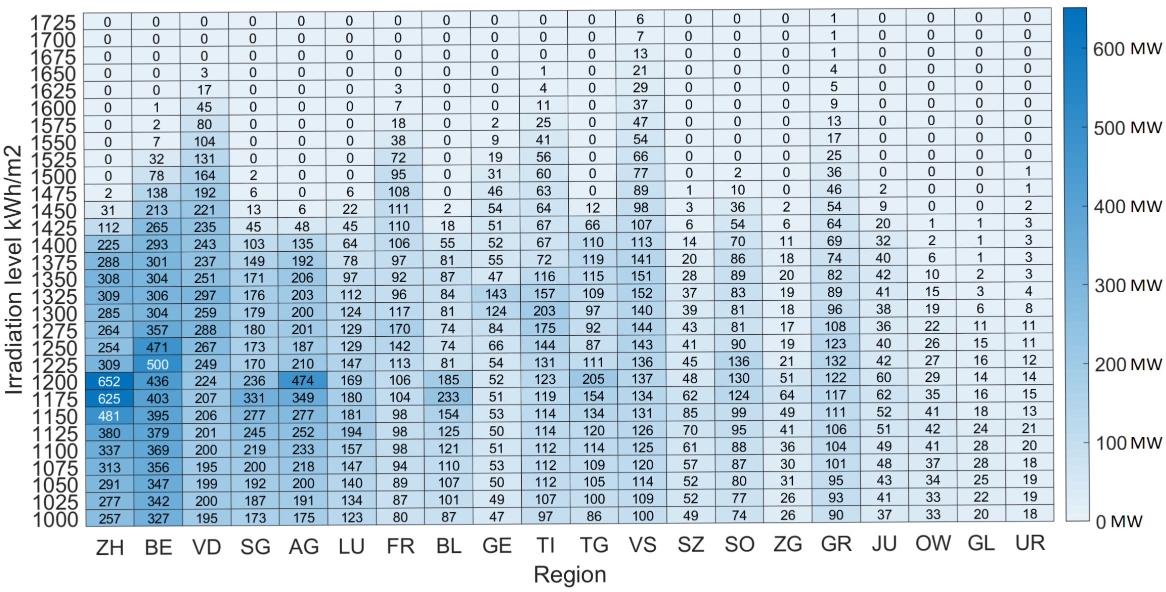


Figure 2: PV investment potential for different regions and irradiation levels in MW.

To lower the computational burden, these nearly 4 million data entries are clustered into different groups depending on their roof size, annual irradiation, warm water consumption (which is used to approximate their electricity consumption), and geographical region:

- **Roof sizes**: roofs are grouped based on their m^2 size into 20 categories [10-24, 24-36, 36-48, 48-60, 60-72, 72-96, 96-120, 120-144, 144-168, 168-210, 210-282, 282-354, 354-426, 426-498, 498-570, 570-900, 900-1'800, 1'800-3'000, 3'000-6'000, $>$6'000].
- **Irradiation levels**: roofs are grouped based on their annual irradiation level in kWh/m^2/year into 4 categories [1'000-1'150, 1'150-1'300, 1'300-1'450, and $>$1'450].
- **Electricity consumption**: roofs are grouped based on their annual electricity consumption in kWh/year[7] into 6 categories [0-2'500, 2'500-4'500, 4'500-7'500, 7'500-13'000, 13'000-30'000, and $>$30'000].
- **Region**: roofs are grouped based on their location/region corresponding to either of the 26 cantons or the 143 districts in Switzerland.

After clustering, all data entries are categorized into either the 20*4*6*26 = 12'480 or the 20*4*6*143 = 68'640 residential customer groups which will be referred to as customer groups in the following context. The economic viability of PVB systems across the nearly 4 million rooftops considered in Switzerland is analyzed by evaluating each customer group using the median values from within each group.

The electricity consumption categories are associated with a specific combination of the 15 consumer types defined within data provided on the historical retail electricity prices and network fees. Table 30 provides the mapping between the 6 consumer level categories and the 15 consumer types.

It is worth noting that the irradiation, roof size and electricity consumption categorizations should be adapted depending on the regions they are applied to. For example, while an average Swiss four-person household consumes 4500 to 5000 kWh of electricity per year (including electric hot water preparation) [80], the average household consumption in other regions might be higher or lower than this. Further-

[7] Since the annual electricity consumption data are not available, the annual electricity load is approximated as 125% of the warm water consumption [77, 78, 79]

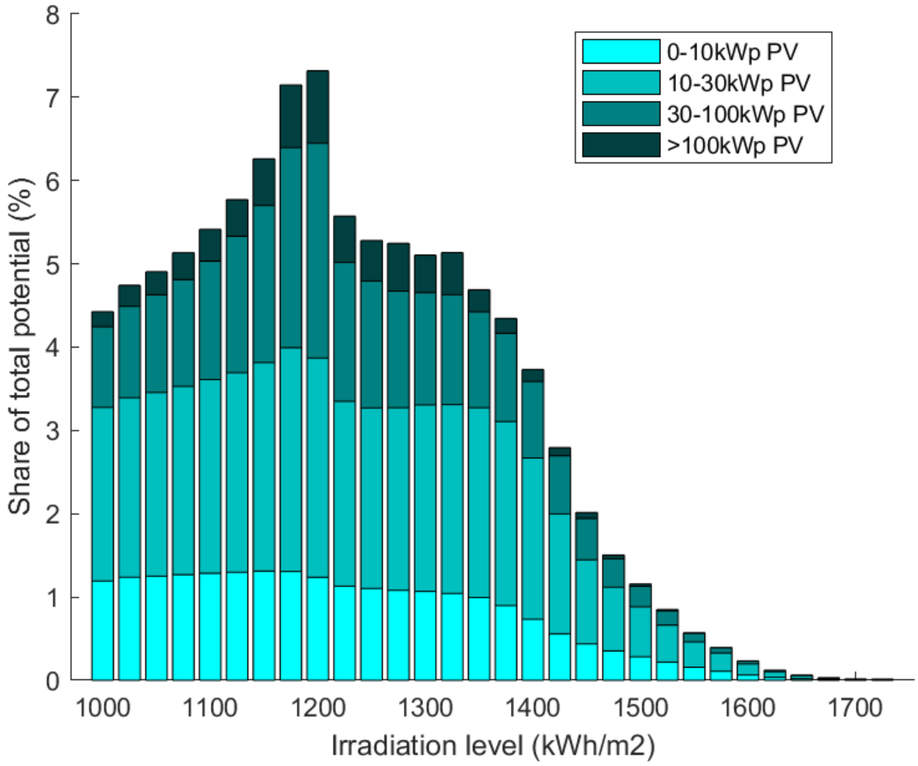


Figure 3: Distribution of the PV investment potential for different PV size categories and irradiation levels.

Table 30: Mapping consumption level categories with consumer types

Consumer level	**Consumption (kWh/yr)**	**Consumer Type Mapping**
1	0 - 2'500	H1
2	2'500 - 4'500	H2 & H3
3	4'500 - 7'500	H3 & H4
4	7'500 - 13'000	H8
5	13'000 - 30'000	H7
6	$>$ 30'000	C2

more, all of the resulting customer groups are considered, although some might not be realistic (e.g., groups with large roof areas and low electricity consumption levels) and have zero rooftops assigned into these customer groups. Thus, a feasibility check could be used to exclude these groups from the analysis. Nevertheless, the feasibility check was not considered for the current modeling methodology, as it does not affect the final results, has negligible impact on the computational time, and might require additional effort for determining the range of reasonable combinations.

The PV electricity generation profiles are created using historical irradiation data from the MeteoSwiss IDAWEB portal [81]. Profiles for each region utilize data from the meteorological stations located nearest to the region. The irradiation profiles are then scaled according to the annual irradiation category collected from the Sonnendach data. A perfect forecast of PV generation is assumed and the generation profile is calculated as the production resulting from the invested module area, module efficiency, inverter efficiency, performance ratio and the irradiation profile.

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 total electricity demand of Switzerland and the neighboring EU countries, we utilize available data for the hourly profiles of demand, when available, as well as data for the desired annual demand in a given year (Section 3.1.1). When the demand profile data are not available, profiles from previous years are scaled to reach the desired annual total for the target year. Additionally, electricity demands from some specific sectors (e.g., industry, e-mobility, heat pumps, etc.) are separately quantified and represented to include both the existing electricity demands of these sectors as well as the future electrification of these demands (Section 3.1.2). Once quantified these specific sector demands are subtracted from the total demand profiles to yield the remaining conventional electricity demand profiles.

3.1.1 Total electricity demand and hourly profiles

For Switzerland, the 2018 profile of the hourly electricity demand is available from Swissgrid [82]; while for the hourly profile of neighboring countries, we use 2018 data available from the ENTSO-E Power Statistics data site [83]. These profiles are all for the year 2018 and are used for the 2018 calibration simulation (note the 2018 Swiss profile from Swissgrid is not used directly and is instead scaled to the 2018 annual demand as reported by the BFE). However, in all 2020-2050 scenario-years, these profiles are not available for Switzerland; so instead the 2018 profile is scaled to ensure that the annual electricity demand for Switzerland matches the desired totals for any scenario-year. The annual Swiss demand value for 2018 and 2020 are taken from BFE Electricity Statistics annual reports [23, 24] while the values for the 2030-2050 scenario-years are taken from the the recent BFE-sponsored Swiss Energy Perspective 2050+ (EP2050+) study [19].

For the neighboring countries, the hourly demand profiles are not available for 2020. So, similar to the Swiss data, the 2018 profiles are scaled to reach the desired 2020 annual totals. The annual demands in 2020 for the neighboring EU countries are taken from the ENTSO-E Transparency data site [84]. However, for 2030-2040, the hourly demand data are available from the ENTSO-E TYNDP report [36] and are therefore used directly. For 2050, the TYNDP does not directly provide any data, so instead we apply that values for the compound annual growth rate (CAGR) that are provided by TYNDP for each of their scenarios [36]. Table 31 lists the values of CAGR applied for each of the TYNDP scenarios. Using this growth rate, the 2040 hourly demand profile for each region is projected for 2050. Since within their report, ENTSO-E provides data for three scenarios: the NatTrds, the GlobAmb, and the DistEn along with different weather years (i.e., 1982, 1984, 2007), the demands can be set based on the desired scenario and weather year combination. While the data from all three scenarios have been setup, in the current Nexus-e investigations, data from the GlobAmb scenario using weather year 2007 tend to be utilized. It should also be noted that the ENTSO-E TYNDP also provides data for the Swiss electricity demand; however, we prioritize using the demand projections from the EP2050+ instead based on its specificity to Switzerland. Table 32 shows the annual total electricity demands for Switzerland and the neighboring countries in each year simulated using the TYNDP GlobAmb scenario for weather year 2007.

In addition, the neighboring loads are further adjusted to account for cross-border flows to all other

Table 31: The TYNDP values for the CAGR are used to quantify the 2050 hourly demand profiles based on the 2040 demand profiles.

TYNDP Scenario	CAGR
National Trends	0.4
Global Ambition	0.2
Distributed Energy	0.7

Table 32: Annual electricity demand (MWh) for Switzerland and the neighboring countries for the 2018 reference year and the 2020-2050 scenario-years.

Country / Year	2018	2020	2030	2040	2050
Switzerland	61,984,000	59,904,000	64,141,361	71,459,875	75,986,499
Austria	71,232,601	68,333,170	85,515,578	98,657,322	100,648,322
France	475,691,835	449,069,799	457,704,451	504,881,170	515,070,159
Germany	517,588,394	503,473,811	580,319,618	566,376,596	577,806,622
Italy	322,166,647	296,094,318	337,727,391	354,324,243	361,474,847

EU countries (e.g., AT-CZ, AT-HU, AT-SL, DE-CZ, DE-DK, DE-LU, DE-NL, DE-PL, DE-SE, FR-BE, FR-GB, FR-ES, IT-GR, IT-MT, IT-SL) using the 2018 hourly cross-border flow data from the ENTSO-E Transparency platform [85]. Unless other data for future cross-border flows are available, these hourly 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 2018 values). Table 33 shows the net annual cross-border flows between Swiss neighboring countries and the other EU countries.

Table 33: 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**			
-10,749,912	3,177,797	3,678,347			
DE to CZ	**DE to DK**	**DE to LU**	**DE to NL**	**DE to PL**	**DE to SE**
2,713,166	1,444,017	4,140,380	19,366,113	7,035,801	-826,364.
FR to BE	**FR to GB**	**FR to ES**			
8,591,712	12,982,376	11,976,316			
IT to GR	**IT to MT**	**IT to SL**			
-432,631	597,741	-6,694,993			

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) [86]. Having the municipal borders from swisstopo [87] 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 [88].

3.1.2 Separating specific electricity demands

Currently in development is the creation of electricity demand profiles for specific sectors including the current demand of these sectors as well as their possible future electrification. By separating these electricity demands from the total demand detailed in Section 3.1.1, the transition toward electrification can be better represented. Additionally, be modeling these demands individually, their flexibility potential to provide load shifting or load shedding can also be modeled with individual potentials and costs. The focus of ongoing work includes separating the electricity demands of industry, e-mobility, heat pumps, and hydrogen production. The demand profiles and the geospatial allocation of these sector demands will also be individually determined.

Once the electricity demand profiles for these sectors are quantified, these demands would be subtracted from the total demand of the associated country, with the remainder being modeled as the conventional electricity demand and split geospatially described in Section 3.1.1.

3.2 Demand flexibility

In addition to flexibility options from dispatchable generators, Nexus-e also considers the possibility for flexible electricity demand shifting (i.e., DSM). Each type of demand represented, such as conventional or e-mobility, is allowed to shift load in time within defined limits and with defined costs. Since the inclusion of individual sector demands is in development (see Section 3.1.2), only a general DSM applied to the conventional demand profiles of each country is currently part of the stable version of the Nexus-e platform codes. However, as other separate demand profiles have been and continue to be included for individual projects, the possible shifting of these individual demands will continue to be represented.

Currently the shifting potential of DSM is limited by a maximum hourly power shift (i.e., no more than this amount of power can be shifted up or down in any hour) and a maximum daily energy shift (i.e., no more than this amount of energy can be shifted up or down in any given day). Additionally, another constraint ensures that within each day the total upward and downward energy shifts are equal (i.e., everything shifted up must also be shifted down in the same day). Depending on the type of demand being shifted, other formulations of these constraints could be defined to better represent a specific sector's demand flexibility potential.

For Switzerland, the potential for DSM is modeled within the distribution level of the electricity system (i.e., in DistIv) since most consumers who would be providing this flexibility are located at this level. Table 34 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 [89, 90], 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. These potentials are distributed to different regions based on their annual demand levels. The total shifting potential of demand is also split between demand of consumers with and without PV units based on the ratio of their annual 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 since it is used voluntarily to decrease their own electricity bills. The lack of available data for DSM costs is a significant issue currently; therefore, in this work the DSM cost was determined from a sensitivity analysis of the daily maximum and minimum wholesale electricity prices for various historical and future year simulations. The costs assumed for DSM will continue to be updated as more relevant literature is published.

Table 34: Overview of Swiss DSM potential constraints

DSM potential limits	2020	2030	2040	2050
Maximum power shift per hour [GW]	0.7	0.9	1.0	1.0
Maximum energy shift per day* [GWh]	2.1	2.7	3.0	3.0

(*) the combined total upward and downward shift within one day would be twice this value

For the other European countries, the potential for DSM is modeled at the centralized level (i.e., in CentIv) since the aggregated representation of these regions is only modeled at this level. Data for the DSM potential within each EU country are taken from the 2020 ENTSO-E TYNDP scenarios [36]. The data available from the TYNDP, which lists the installed capacities by country for DSM, are implemented as the maximum hourly shiftable power limits. ENTSO-E provides data for three scenarios: the NatTrds, the GlobAmb, and the DistEn. Table 35 presents these values for the total maximum power that can be shifted per hour taken from the GlobAmb scenario along with the assumed total energy that can be shifted per day for each of the neighboring EU countries. The daily energy shifting limit is set based on the assumptions utilized in the Swiss case that the maximum power shift could be applied to three hours per day. Hence, the maximum daily energy shift is three times the maximum hourly power shift.

Table 35: Overview of EU DSM potential constraints taken from the TYNDP Global Ambition scenario

Country	DSM potential limits	2020	2030	2040	2050
DE	Maximum power shift per hour [GW]	0.0	5.9	5.9	5.9
DE	Maximum energy shift per day* [GWh]	0.0	17.7	17.7	17.7
FR	Maximum power shift per hour [GW]	0.0	3.4	3.4	3.4
FR	Maximum energy shift per day* [GWh]	0.0	10.2	10.2	10.2
IT	Maximum power shift per hour [GW]	0.0	2.3	2.3	2.3
IT	Maximum energy shift per day* [GWh]	0.0	6.9	6.9	6.9
AT	Maximum power shift per hour [GW]	0.0	0.0	0.0	0.0
AT	Maximum energy shift per day* [GWh]	0.0	0.0	0.0	0.0

(*) the combined total upward and downward shift within one day would be twice this value

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) [16] 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 [91]. In Nexus-e, we assume 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 [92]. Table 36 shows the average, maximum and minimum hourly values for each reserve requirement that Swissgrid procured in 2015[8]. We use these data for the 2018 calibration process and also maintain these requirements as the basis for the 2020-2050 scenario simulations. All dispatchable generator types are allowed to offer their capacity for the procurement of these reserves.

Table 36: The 2015 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 2018 based on ENTSO-E regulations and in Nexus-e 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 2018 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 [91]. For the tertiary reserve, the 2018 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, as shown in Eqs. (1) and (2), with the appropriate contribution from wind, (B^{+w}_{mcyt} or B^{-w}_{mcyt}), and solar, (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.

[8] 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.

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

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

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 [81]. 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 [93, 94, 95, 96]. The most relevant literature surveyed was from the various renewable integration studies conducted by researchers and electricity markets around the world [97, 98, 99, 100]. 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, as shown in 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 [99].

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

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, as shown in 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 [93]. 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 ($\tilde{I}^{R}_{r_s c_s(t+1)}/\tilde{I}^{R}_{r_s c_s t}$).

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

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 [101] and Frouin model [102]. 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 [103], Michalsky [104], and Meeus [105, 106]. 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 fees. Note that the first three are only applied to PV units whereas the last one (i.e. network fee) is applied to all units in the distribution system. While the values defined for these parameters are adjustable depending on the scenario, almost all recently simulated scenarios represent the status quo for the legislative and regulatory framework (i.e., in place and planned) for the following four parts.

5.1.1 PV investment subsidy

Currently, both an output-based feed-in-tariff subsidy scheme and a capacity-based investment subsidy scheme exist in Switzerland. However, the feed-in-tariff scheme is expected to expire in 2022 and due to the long waiting list, only PV units registered before July 2012 could qualify to benefit from it [107]. From 2020 on, units above 100 kWp within the feed-in-tariff scheme are obliged to participate in direct marketing that aims to replace the fixed tariff with a more market-oriented remuneration tariff [108]. Units ranging from 2 kWp to 50 MWp can apply for the one-time capacity-based investment subsidy that could cover up to 30% of their investment costs based on the installed capacity and the PV categorization [66]. The current one-time investment subsidy is valid until 2030, but recent reports indicate that the Swiss federal council is planning a possible extension to 2035 [109].

We include the current investment subsidy for PV units based on BFE regulations [66] until 2020. Beyond 2020, since no data on the specific subsidy payouts are set yet, 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 Table 37. This subsidy is split into three parts: the first is a fixed payment regardless of the PV size, the second is an additional payment for all units that is given for up to 30 kW, and the third is paid only to installations bigger than 30 kW and is given for the portion of the investment above the first 30 kW. 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.

Table 37: The modeled PV investment subsidy decreases in 2030 and is phased-out before 2040.

	2018	2020	2030	2040	2050
Part 1: Basis (Fr.)	1400	1000	800	0	0
Part 2: 0-30 kW PV (Fr./kW)	400	340	272	0	0
Part 3: >30 kW PV (Fr,/kW)	300	300	240	0	0

5.1.2 DSO injection tariff

To account for income earned from PV generation that is fed back into the local electricity grid, the injection tariffs that are set by regional DSOs are included. Since these injection tariffs vary from DSO to DSO and DSO regions and Cantons are only partially congruent, 2020 data available from [110] are used to make an estimation of the average value for each Canton. The estimated average values of the injection tariff by Canton can be found in Table 38.

Table 38: The average 2020 DSO injection tariff in EUR-cent/kWh for PV is estimated for each Swiss Canton.

Index	Canton	Injection tariff
1	ZH	6.63
2	BE	6.90
3	LU	7.27
4	UR	8.97
5	SZ	6.96
6	OW	10.00
7	NW	5.91
8	GL	6.82
9	ZG	11.21
10	FR	8.45
11	SO	8.72
12	BS	11.82
13	BL	9.09
14	SH	7.27
15	AR	5.66
16	AI	9.09
17	SG	8.18
18	GR	9.09
19	AG	6.23
20	TG	7.27
21	TI	8.18
22	VD	7.42
23	VS	7.00
24	NE	8.45
25	GE	11.10
26	JU	6.90

The inclusion of this injection tariff is important for quantifying the revenue earned from PV generation that is not self consumed. Even more critically, it is needed to quantify the economic benefits of the PV-batteries that help increase the earnings of the PVB system by reducing the PV generation sold at this injection tariff by storing for later use 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. However, in the course of previous analyses, it became apparent that such an assumption could result in injection tariffs below the wholesale price. Since this trend is not in line with the planned regulation in Switzerland, additional options are available where the injection tariff expires in 2025 and afterwards the excess PV generation is instead compensated at the wholesale price. Assuming the injection tariff remains constant through 2050 is conservative compared to the option of switching the compensation to be based on the wholesale price.

5.1.3 PV investment tax rebates

Third, we also consider the available tax rebates on the investment of rooftop PV of 7.7% on the operational costs and 20% on the net investment costs (i.e., after subtracting the investment subsidy) [111] that is available in all cantons except Luzern and Graubünden due to regional regulations [112]. We assume these tax rebates to remain constant until 2050.

5.1.4 Consumer network fee

Fourth, within the consumer's electricity cost, we also represent the network fee component. For this network fee, we use the data for 2018 from ElCom (including grid charge and additional fees) [113] and assume the total network fee remains constant until 2050. These 2018 data separate the grid charge and additional fees by region (i.e., Canton) and by consumer type (i.e., there are 15 consumer types represented). The network fee 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 from onsite PV production. More details on the calculation of this network fee as well as the values quantified for each Canton and consumption level category can be seen in Section 5.2.2.

5.1.5 Policies not included

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 2.1.5 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 large enough size to contribute to the electricity market (see Section 2.3 for more details);
- no subsidies for wind generators are included 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 2.1.5 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 [29, 30] (see Section 2.1.5 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 2.1.5 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 and DistAB modules of Nexus-e, the price of electricity for purchasing from or selling to the transmission grid is modeled to reflect a consumer's retail electricity price. By applying such consumer prices, we are able to properly reflect the consumer costs that are offset by self-consuming from PV.

In Nexus-e, the representation of the consumer's retail price is comprised of three parts: (i) the wholesale electricity price which is provided as a signal from the CentIv module, (ii) the total network fee including both the grid charge and additional fees, and (iii) the wholesale-to-retail price markup. Out of these three components of the consumer's retail electricity price, the wholesale-to-retail price markup and network fee 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 vary from year to year and will change depending on the scenario assumptions. In general, the consumer's retail price should increase further into the future due to the increases in CO_2 and fuel prices.

However, before any future scenario-year simulation can be initiated, a historical basis is used to quantify both the total network fee and the wholesale-to-retail price markup that will be applied for a given region and consumption level category. As mentioned in the DistIv individual report, the wholesale-to-retail markup is only applied to the self-consumed portion of the PV and PVB generation to properly reflect the consumer costs that are offset by providing the consumer's demand from PV instead of from purchasing at the consumer's normal cost. For all other distributed technologies, the price of electricity for purchasing from or selling to the transmission grid only comprises the first two parts (i.e., the wholesale price and network fee). The network fee and wholesale-to-retail markup are quantified using known historical data from 2018 [113]. First, data are organized for a target historical retail electricity price (see Section 5.2.1). Next, the network fee data are similarly gathered (see Section 5.2.1) and subtracted from the target retail price. Finally, the average Swiss wholesale electricity price in 2018 [114] is also subtracted from the target retail price, with the remainder being the wholesale-to-retail price markup (see Section 5.2.3).

5.2.1 Quantifying the target historical consumer retail price

Target values for a given consumer's retail electricity price are calculated using 2018 data from [113]. These 2018 data separate the average retail prices by region (i.e., Canton) and by consumer type (i.e., there are 15 consumer types represented, H1-H8 and C1-C7). To calculate the consumer retail prices for any desired consumption level category (see Section 2.3.3 for a description of the consumption level categories) the consumption level is associated with a particular combination of the 15 consumer types based on the details of these consumer types. Table 30 provides the mapping between the 6 consumer level categories and the 15 consumer types. So, for each combination of region and consumption level category, a unique target value for the consumer's retail electricity price is quantified. Table 39 provides these target retail prices.

5.2.2 Quantifying the consumer network fee

Within the consumer's electricity cost, we also represent the network fee component. For this network fee (including grid charge and additional fees), the data for 2018 from ElCom [113] are again utilized. Similar to the target retail electricity price, these 2018 data separate the grid charge and additional fees by region (i.e., Canton) and by consumer type (i.e., there are 15 consumer types represented, H1-H8 and C1-C7). The network fee 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 from onsite PV production. To calculate the network fees for any desired consumption level category (see Section 2.3.3 for a description of the consumption level categories) the consumption level is associated with a particular combination of the 15 consumer types based on the details of these consumer types. Table 30 provides the mapping between the 6 consumer level categories and the 15 consumer types. So, for each combination of region and consumption level category, unique target values for the consumer's grid charge and additional fees are quantified. Table 40 provides the resulting total network fee (i.e., grid

Table 39: The calculated 2018 average consumer retail electricity prices in EUR-cent/kWh varies by Canton and consumption level category.

		Consumption level category (kWh/yr)					
Index	**Canton**	**0-2'500**	**2'500-4'500**	**4'500-7'500**	**7'500-13'000**	**13'000-30'000**	**>30'000**
1	ZH	20.45	16.72	15.82	15.55	14.26	14.29
2	BE	27.66	23.05	22.12	22.21	19.74	19.88
3	LU	22.98	21.02	20.73	22.10	17.80	17.05
4	UR	28.37	23.31	22.22	22.24	19.16	16.72
5	SZ	23.88	20.14	19.15	18.74	16.93	16.74
6	OW	26.90	22.11	21.03	20.77	19.05	17.73
7	NW	24.18	19.91	18.85	18.14	17.04	16.13
8	GL	27.73	22.32	20.09	18.54	17.11	19.46
9	ZG	21.04	18.21	17.41	17.72	14.89	15.26
10	FR	24.52	20.13	19.29	19.77	17.35	19.12
11	SO	26.09	21.64	20.66	20.62	18.56	18.81
12	BS	27.43	25.83	25.90	27.34	23.10	25.64
13	BL	25.36	21.54	20.66	20.40	17.07	18.81
14	SH	24.75	20.60	19.59	19.07	16.36	16.65
15	AR	20.96	17.76	16.60	15.97	14.17	13.50
16	AI	22.17	17.63	16.52	15.86	14.30	14.07
17	SG	23.18	18.84	17.68	16.99	15.47	15.18
18	GR	24.89	21.06	20.38	20.37	18.85	19.55
19	AG	26.78	18.69	17.56	17.03	15.50	16.21
20	TG	23.22	18.99	17.92	17.34	15.95	16.54
21	TI	21.44	18.89	18.63	18.56	17.01	19.22
22	VD	24.14	20.91	20.18	20.49	18.28	17.70
23	VS	20.28	17.30	18.59	15.41	15.98	15.18
24	NE	25.41	21.40	20.12	20.20	18.01	18.80
25	GE	20.46	19.10	18.99	19.96	18.07	19.52
26	JU	32.18	26.32	25.30	25.59	21.10	21.81

charge plus additional fees) for each Canton and consumption level.

5.2.3 Quantifying the wholesale-to-retail price markup

To properly represent the consumer's retail electricity prices in future years, historical data are used to quantify the markup necessary to make up the difference between the 2018 target retail price and the 2018 wholesale price plus the 2018 network fee (i.e., the wholesale-to-retail markup is calculated by subtracting the wholesale price and total network fee components from the target retail price). Unique values of this wholesale-to-retail price markup are quantified by region (i.e., Canton) and by consumer type (i.e., there are 15 consumer types represented, H1-H8 and C1-C7). While both the target retail price and network fee use data from ElCom [113], the 2018 wholesale price data are taken from ENTSO-E [114]. So, for each combination of region and consumption level category, a unique value for the consumer's wholesale-to-retail markup is quantified. Table 41 provides these wholesale-to-retail price markups.

Table 40: The calculated 2018 average consumer network fees in EUR-cent/kWh varies by Canton and consumption level category.

		Consumption level category (kWh/yr)					
Index	**Canton**	**0-2'500**	**2'500-4'500**	**4'500-7'500**	**7'500-13'000**	**13'000-30'000**	**>30'000**
1	ZH	9.79	8.69	8.33	8.08	6.83	6.97
2	BE	17.38	13.46	12.56	12.16	9.30	9.25
3	LU	11.01	10.11	10.07	10.77	7.59	8.82
4	UR	18.08	13.31	12.22	12.02	9.63	9.19
5	SZ	14.10	10.63	9.75	9.18	8.09	8.60
6	OW	16.21	12.60	11.72	11.27	10.17	9.13
7	NW	14.92	10.80	9.73	8.87	9.63	7.12
8	GL	17.57	13.85	12.68	11.02	9.19	12.15
9	ZG	11.94	9.00	8.42	8.74	7.09	8.28
10	FR	12.95	9.18	8.36	8.32	6.53	6.57
11	SO	14.85	11.19	10.05	9.37	8.09	8.83
12	BS	17.40	15.99	16.05	17.31	13.93	16.58
13	BL	13.95	10.51	9.64	9.07	6.48	8.82
14	SH	15.96	12.31	11.29	10.62	8.09	8.94
15	AR	11.13	9.39	8.27	7.37	6.28	6.35
16	AI	13.94	9.61	8.49	7.62	6.57	7.06
17	SG	14.91	10.65	9.68	8.87	7.30	7.92
18	GR	15.98	12.43	11.17	10.20	9.26	9.72
19	AG	14.75	10.50	9.40	8.66	7.50	8.12
20	TG	15.31	11.04	10.00	9.40	8.31	8.85
21	TI	12.65	10.07	9.69	9.86	8.25	11.17
22	VD	13.18	10.45	9.74	9.60	8.17	7.92
23	VS	11.87	9.08	8.28	7.44	6.97	6.76
24	NE	14.89	11.90	11.08	10.63	9.16	9.22
25	GE	9.70	8.91	8.85	9.42	8.54	8.67
26	JU	19.06	14.28	13.27	13.15	9.77	10.25

Table 41: The calculated 2018 consumer wholesale-to-retail price markup in EUR-cent/kWh varies by Canton and consumption level category.

		Consumption level category (kWh/yr)					
Index	**Canton**	**0-2'500**	**2'500-4'500**	**4'500-7'500**	**7'500-13'000**	**13'000-30'000**	**>30'000**
1	ZH	5.44	2.80	2.27	2.25	2.20	2.10
2	BE	5.06	4.37	4.33	4.82	5.22	5.40
3	LU	6.74	5.69	5.45	6.11	4.99	3.00
4	UR	5.07	4.78	4.77	4.99	4.30	2.31
5	SZ	4.56	4.28	4.18	4.33	3.62	2.92
6	OW	5.46	4.29	4.09	4.28	3.66	3.37
7	NW	4.04	3.88	3.90	4.05	2.18	3.79
8	GL	4.93	3.25	2.19	2.30	2.70	2.09
9	ZG	3.88	3.99	3.77	3.76	2.58	1.76
10	FR	6.34	5.72	5.71	6.22	5.60	7.33
11	SO	6.02	5.23	5.39	6.03	5.25	4.75
12	BS	4.81	4.62	4.63	4.80	3.94	3.84
13	BL	6.18	5.80	5.80	6.12	5.36	4.76
14	SH	3.57	3.07	3.08	3.23	3.05	2.49
15	AR	4.61	3.14	3.11	3.37	2.67	1.93
16	AI	3.00	2.79	2.81	3.02	2.51	1.79
17	SG	3.05	2.97	2.78	2.89	2.94	2.03
18	GR	3.69	3.40	3.99	4.94	4.36	4.61
19	AG	6.80	2.97	2.93	3.14	2.78	2.88
20	TG	2.69	2.73	2.70	2.72	2.41	2.46
21	TI	3.57	3.59	3.72	3.48	3.53	2.83
22	VD	5.74	5.24	5.22	5.68	4.89	4.56
23	VS	3.19	2.99	5.09	2.75	3.79	3.20
24	NE	5.29	4.28	3.82	4.34	3.62	4.35
25	GE	5.54	4.97	4.92	5.32	4.31	5.63
26	JU	7.90	6.82	6.81	7.22	6.11	6.34

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 [115]. 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) [116]. 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 [116], shows the average income and expenditure of households in Switzerland for the year 2016.

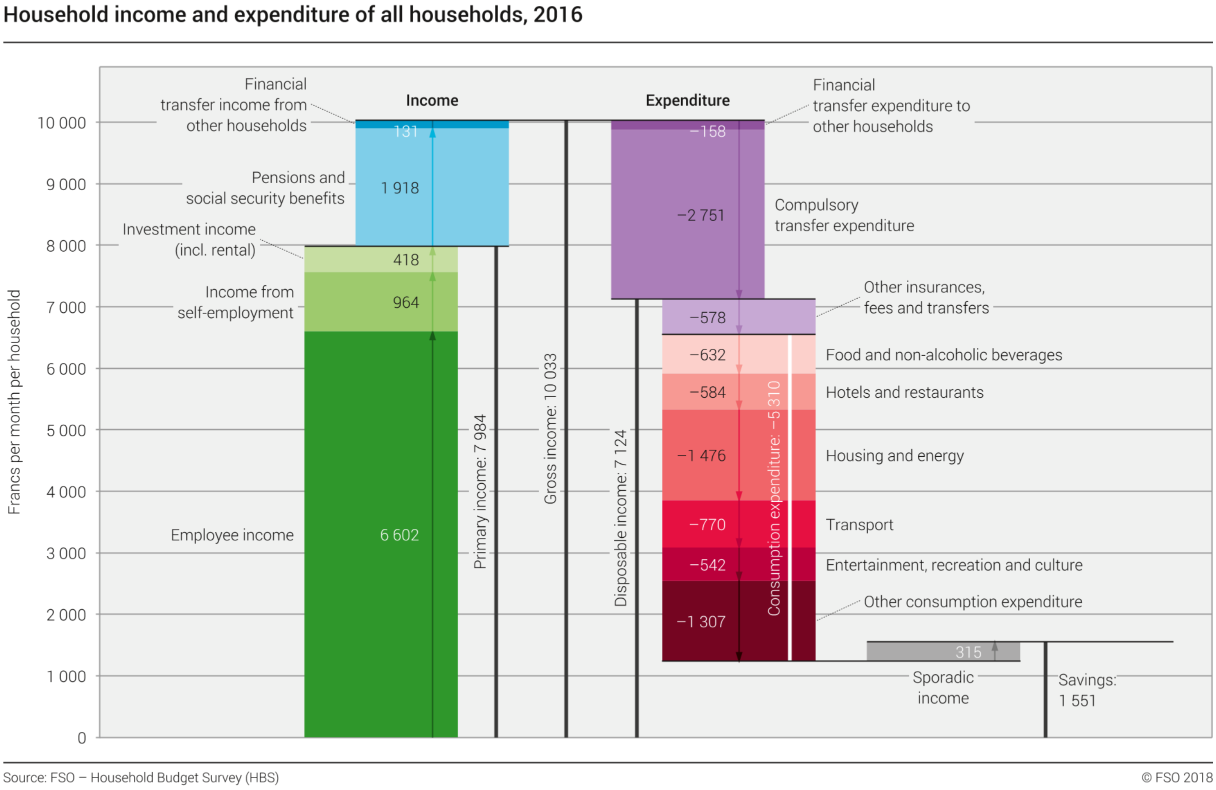


Figure 4: Average income and expenditure of households in Switzerland for the year 2016.

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 42) 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 42: 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

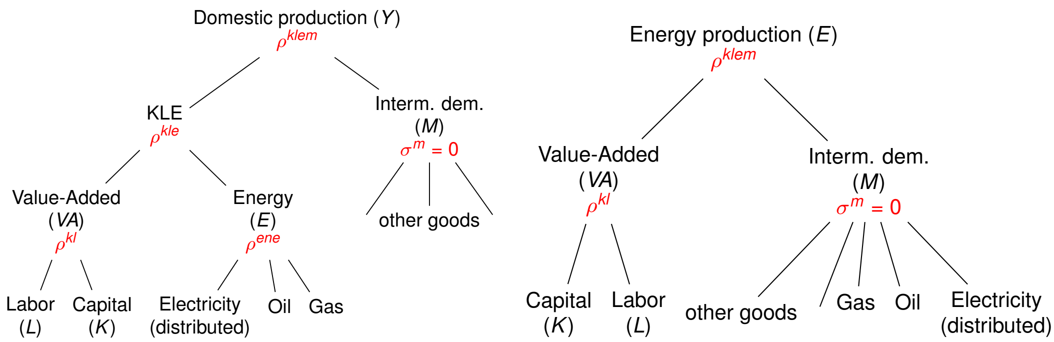
[1] Differentiated Input–Output Table for the Energy Sector 2014 [115].
[2] VGR: National income accounts [117]
[3] BSV: Federal Office of Social Insurance [118]

6.2 Elasticities for domestic production and international trade

GemEI 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 [119] 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.[9] Table 43 contains the values or range of the chosen sectoral elasticities.

[9] 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 43: 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	[120]
σ_i^{kle}	0.09 - 1.27	elasticity parameter between Value-Added and Energy (KLE) nest	[120]
σ_i^{kl}	0.06 - 3.36	elasticity parameter between Capital and Labor (KL) nest	[120]
σ^{ene}	0.5	elasticity parameter between Electricity, Oil, and Gas (ene) nest	[121]
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 [122]). Table 44 contains the values or range of the chosen elasticities.

Table 44: 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 [123]
τ	1.3 - 8.0	transformation parameter between export and domestic demand	Own calculations based on [123] and [124]

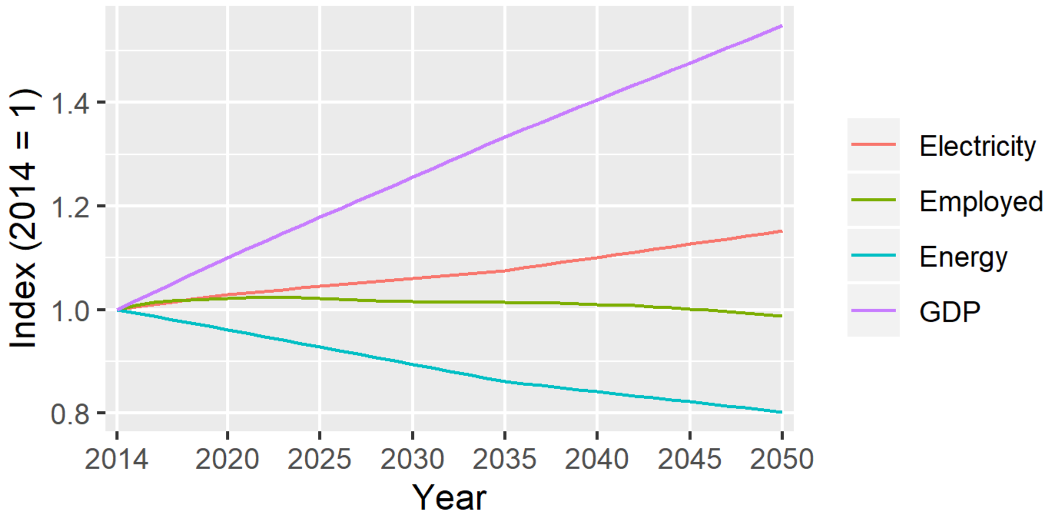
6.3 Baseline equilibrium growth path

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 45 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 [125].

Table 45: Assumed projections for the Swiss population, GDP and energy demand according to Swiss Energy Modelling Platform [126].

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 [126]



7 Scenarios

Many of the input parameters (e.g., surrounding country capacities, available Swiss generator candidates, fuel prices, nuclear lifetime, Swiss NTCs, etc.) are customizable in order to facilitate the creation of contrasting scenarios depending on the research questions to be investigated. This section provides a brief description of some of the options for adjusting input parameters towards creating different scenario options. Throughout the discussion below, one scenario is considered to include all relevant scenario-years (i.e., 2020-2050).

The majority of all adjustable parameters for creating contrasting scenarios can be grouping into four categories:

1. Developments for Switzerland
2. Developments for neighboring countries (e.g., EU)
3. Options for the electricity market and trade
4. Options for technology developments, commodity prices, and general inputs

Related to possible developments for Switzerland, different options could be defined with unique potentials for new generating capacity investments as well as flexibility options, such as options for new gas-fired generators, alpine PV, or battery energy storage system (BESS). Similarly, different options could be compared for the schedule of the nuclear power phaseout. Various assumptions could be defined for the electrification of transport and heating (e.g., e-mobility and heat pumps) that yield unique cases for electricity demand. Other developments could be included that cover: domestic hydrogen demand, the use of hydrogen for electricity storage, and the possibility of utilizing the available flexibility of demand shifting from any one of the defined electricity demands.

Beyond Switzerland, the influence of the surround EU developments could be assessed through different options for installed capacities, demands, and flexible resources (i.e., the three TYNDP scenarios). Additionally, scenarios can be created based on different weather years that give a wider perspective on the possibility for wet/dry years or warm/cold years.

Scenario options can be adjusted to represent different developments of the electricity market. Of particular interest, based on the planned development of EU policy, is the impact of possible restrictions on the electricity trade with Switzerland. Scenarios can be created with different possible limitations for the maximum allowed trade flows between any two countries. Such scenarios could also cover the possible expansion of the flow-based region of Europe.

Finally, the last category for scenario creation covers options for different projections of technology developments (e.g., faster cost reduction in PV and BESS) as well as assumptions about commodity prices, such as the price of natural gas or CO_2. Other, more general, inputs can also be adjusted including the assumptions about inflation and interest rates.

While these provided examples, which represent varying input assumptions, can be used to create a wide range of contrasting scenarios, many other options are available based on the vast input data needed for the Nexus-e platform. New scenarios will continue to be created and used to investigate and answer relevant questions about the impact of possible future developments in the Swiss and European electricity system.

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