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# Axpo Energy Reports

## Scenario Analysis with Focus on Winter Power Supply

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## Zusammenfassung

Dieser Bericht bewertet die winterliche Stromversorgung von Schweiz im Jahr 2050 anhand von sechs von Axpo entwickelten Szenarien und untersucht, wie diese Portfolios mit alternativen Konfigurationen des europäischen Energiesystems interagieren. Die Analyse wird durch die *Winterlücke* in der Schweiz motiviert – eine bereits bestehende saisonale Diskrepanz zwischen Stromnachfrage und inländischem Angebot, die sich unter den derzeitigen Transformationspfaden voraussichtlich weiter verstärken kann.

Es ist wichtig zu betonen, dass diese Studie nicht die zugrunde liegenden Entscheidungen, Annahmen oder politischen Beweggründe bewertet, die zur Definition der analysierten Szenarien geführt haben. Diese Szenarien werden als exogene Eingaben behandelt. Ziel der Analyse ist vielmehr eine transparente, quantitative und unabhängige Bewertung ihrer Auswirkungen.

Die Szenarien werden entlang mehrerer zentraler Dimensionen bewertet, darunter strukturelle Versorgungssicherheit, marktbasiertes Dispatch, die Rolle der Wasserkraft und saisonaler Speicher, der Beitrag erneuerbarer Energien, der Bedarf an steuerbarer Erzeugungskapazität, der Wert von Flexibilitätsoptionen sowie der Einfluss von Marktintegration und grenzüberschreitendem Austausch. Dieser Ansatz ermöglicht einen konsistenten Vergleich der langfristigen Systemleistung und hebt die wesentlichen Treiber der winterlichen Versorgungssicherheit hervor.

Die Ergebnisse hängen von den spezifischen Modellannahmen, Eingangsdaten und Randbedingungen ab, die in dieser Studie verwendet wurden. Sie sollten daher nicht als Prognosen oder Vorhersagen interpretiert werden, sondern als illustrative Darstellungen des Systemverhaltens unter definierten Bedingungen.

Die Ergebnisse sollen eine vergleichende Bewertung und fundierte Entscheidungsfindung unterstützen, indem sie zentrale Zielkonflikte, Sensitivitäten und strukturelle Treiber der winterlichen Versorgungssicherheit aufzeigen.

Ein zentraler Beitrag der Studie besteht darin, zwischen zwei häufig vermischten Konzepten der winterlichen Versorgungssicherheit zu unterscheiden. Das erste sind die *Winter-Nettoimporte*, die das Ergebnis eines wirtschaftlich effizienten grenzüberschreitenden Stromhandels in einem integrierten europäischen Markt widerspiegeln. Das zweite ist die *Winter-Importabhängigkeit*, die die strukturelle Abhängigkeit von Importen misst, definiert als das minimale Stromimportvolumen, das erforderlich ist, um die winterliche Nachfrage zu decken. Diese Unterscheidung ist entscheidend, da hohe Winterimporte nicht zwangsläufig auf unzureichende inländische Ressourcen hinweisen; sie können auch einfach wirtschaftlich attraktive Importe aus Nachbarländern widerspiegeln.

Die Analyse basiert auf stündlichen wirtschaftlichen Dispatch-Simulationen mit dem FlexECO-Tool von Forschungsstelle Energienetze (FEN) der ETH zürich. Sechs Schweizer-Szenarien werden betrachtet, die jeweils unterschiedliche Energieportfolios widerspiegeln, und mit zwei möglichen Entwicklungspfaden des europäischen Energiesystems kombiniert: einem Axpo-Referenzfall und einem auf TYNDP basierenden Szenario mit höherem Anteil erneuerbarer Energien. Zwei Betriebsmodi werden angewendet: (i) ein *marktintegrierter Modus* mit unbeschränktem Handel (unter Berücksichtigung von Übertragungskapazitäten) und (ii) ein *Quasi-Autarkie-Benchmark*, bei dem Stromexporte aus Schweizer deaktiviert und Stromimporte nach Schweiz auf den Einsatz als letztes Mittel beschränkt werden. Dieses duale Rahmenwerk trennt marktbetriebene Ergebnisse von struktureller Winterversorgungssicherheit.

Die Ergebnisse zeigen, dass alle sechs in dieser Studie analysierten Schweizer-Szenarien die strukturelle Winter-Importabhängigkeit im Quasi-Autarkie-Benchmark auf 5 TWh begrenzen können. Unter den Annahmen der Studie deutet dies darauf hin, dass die vorgeschlagenen Portfolios ausreichend inländische Ressourcen enthalten, um die winterliche Nachfrage mit nur begrenzter Importabhängigkeit zu decken. In den markintegrierten Simulationen importiert Schweiz jedoch in allen Szenarien im Winter deutlich mehr Strom und exportiert im Sommer. Dies stellt keinen Widerspruch dar, sondern zeigt, dass Winter-Nettoimporte stark von Strompreisen und den Bedingungen im europäischen System beeinflusst werden. Schweiz importiert tendenziell dann, wenn ausländischer Strom günstiger ist, selbst wenn inländische Kapazitäten verfügbar sind. Daher sind Nettoimporte allein kein verlässlicher Indikator für die winterliche Versorgungssicherheit.

Die Wasserkraft erweist sich als eine der zentralen Säulen der winterlichen Versorgungssicherheit von Schweizer. Speicherwasserkraft ermöglicht eine erhebliche saisonale Verschiebung von Energie vom Sommer in den Winter, in der Größenordnung von etwa 7 TWh pro Jahr unter den modellierten Annahmen. Diese saisonale Verschiebung wird nicht nur in den Quasi-Autarkie-Simulationen beobachtet, wo sie direkt zur Versorgungssicherheit beiträgt, sondern auch in den markintegrierten Simulationen, was darauf hinweist, dass sie auch wirtschaftlich attraktiv ist. Mit anderen Worten: Wasser im Sommer zu speichern und im Winter zu nutzen, ist sowohl für die Versorgungssicherheit wertvoll als auch wirtschaftlich sinnvoll. Gleichzeitig bietet Speicherwasserkraft erhebliche kurzfristige Flexibilität. Wenn kostengünstige Importe aus Europa verfügbar sind, wird die Wasserkrafterzeugung reduziert, um Wasser zu sparen, während sie in Zeiten (europaweiter) Stromknappheit erhöht wird und häufig auch Exporte unterstützt. Die Schweizer Speicherwasserkraft fungiert somit sowohl als saisonale Versorgungsressource als auch Bindeglied für die Systemflexibilität zum europäischen System.

Pumpspeicherkraftwerke tragen in erster Linie zur kurzfristigen Systembalance bei, indem sie überschüssigen Strom aufnehmen und in Zeiten höherer Preise wieder erzeugen. Obwohl das Modell darauf hinweist, dass Pumpspeicher auch zur längerfristigen Energieverschiebung beitragen können, sollte dies eher als technisches Potenzial denn als etabliertes Betriebsverhalten interpretiert werden.

Zusätzliche Flexibilität durch Batterien und Lastmanagement hat einen begrenzten Einfluss auf saisonale Importmuster und die winterliche Energiebilanz, solange Schweiz gut in das europäische System integriert ist. Unter stärker eingeschränkten Bedingungen können diese Ressourcen jedoch zur Winterversorgung beitragen, indem sie zeitliche Ungleichgewichte zwischen Erzeugung und Nachfrage verringern, insbesondere in Szenarien mit hohen Anteilen erneuerbarer Energien (insbesondere Solarenergie). Im Rahmen dieser Studie erscheint ihr Beitrag zur Aufrechterhaltung des angestrebten Niveaus der Winterversorgungssicherheit als eher gering.

Die Szenarien verdeutlichen zudem strukturelle Unterschiede zwischen Solar- und Windenergie. Solarbasierte Portfolios führen zu ausgeprägten täglichen Ungleichgewichten und großen Sommerüberschüssen, die mit den verfügbaren Speichern nicht vollständig in den Winter verschoben werden können, was zu Abregelungen führt, wenn Exportmöglichkeiten eingeschränkt sind. Windenergie ist zeitlich gleichmäßiger verteilt und trägt relativ stärker im Winter bei, wodurch saisonale Ungleichgewichte reduziert und die Versorgungssicherheit verbessert werden.

Steuerbare Erzeugung, insbesondere Gaskraftwerke und Kernenergie, erweist sich als entscheidend zur Begrenzung der winterlichen Importabhängigkeit. Ohne steuerbare Kapazitäten kann das System unter den Annahmen der Studie nicht unter dem 5 TWh-Benchmark bleiben. Allerdings unterscheiden sich die Nutzungsmuster im markintegrierten Betrieb: Gaskraftwerke laufen hauptsächlich in Knappheitssituationen und weisen geringe Volllaststunden auf, während Kernkraftwerke ganzjährig mit hoher Auslastung betrieben werden und zudem Elektrolyse, Speicher und Exporte unterstützen. Dies verdeutlicht einen zentralen Zielkonflikt: Steuerbare Kapazitäten können für die Versorgungssicherheit notwendig sein, werden in einem effizienten Marktumfeld jedoch je nach Technologie nur intermittierend genutzt.

Die Entwicklung des europäischen Energiesystems hat einen erheblichen Einfluss auf den Betrieb der Schweizer-Anlagen. Im TYNDP-basierten Szenario mit höherem Anteil erneuerbarer Energien importiert Schweiz häufiger Strom aufgrund der größeren Verfügbarkeit kostengünstiger Energie im Ausland. Umgekehrt führt eine Reduktion der grenzüberschreitenden Übertragungskapazitäten (zwischen Schweiz und seinen Nachbarländern) zu einer stärkeren Nutzung inländischer steuerbarer Erzeugung und reduziert arbitragegetriebene Wasserkraftnutzung. Versorgungssicherheit und Importabhängigkeit müssen daher stets gemeinsam mit Annahmen zur europäischen Marktentwicklung und Integration bewertet werden.

Sensitivitätsanalysen auf Basis einer nodalen Darstellung des Schweizer-Übertragungsnetzes im Vergleich zu einer vereinfachten Kupferplattenmodellierung zeigen, dass interne Netzengpässe Spitzenflüsse dämpfen und Dispatchmuster glätten, jedoch die grundlegenden Ergebnisse nicht wesentlich verändern. Die systemischen Rollen von Wasserkraft, erneuerbaren Energien und steuerbarer Erzeugung bleiben robust, was darauf hindeutet, dass eine Ein-Knoten-Darstellung des Schweizer-Stromsystems für die Zwecke dieser Studie ausreichend ist.

Insgesamt ist die winterliche Stromherausforderung von Schweiz nicht lediglich eine Frage der inländischen Kapazitäten. Es handelt sich vielmehr um ein systemisches Thema, das durch das Zusammenspiel von Erzeugungsportfolios, wasserkraftbasierter Flexibilität, steuerbaren Ressourcen und europäischen Marktdynamiken geprägt wird. Während alle sechs betrachteten Szenarien die strukturelle Importabhängigkeit auf das Zielniveau begrenzen können, dürften die tatsächlichen Winterimporte höher bleiben, sobald Marktbedingungen Importe begünstigen. Bewertungen der Versorgungssicherheit sollten daher über reine Nettoimportkennzahlen hinausgehen und strukturelle Abhängigkeiten sowie eine umfassendere Systemperspektive berücksichtigen.

Zukünftige Arbeiten sollten die Analyse um Unsicherheiten bei Wetter und Ausfällen erweitern, eine detailliertere Abbildung von Wasserkraftkaskaden und betrieblichen Einschränkungen integrieren, die Modellierung des europäischen Marktdesigns und der Sektorkopplung verbessern sowie Batterien, Lastmanagement und Netzrestriktionen unter operativer Unsicherheit realistischer darstellen. Diese Erweiterungen würden eine umfassendere und stärker betrieblich fundierte Bewertung der zukünftigen winterlichen Versorgungssicherheit von Schweiz ermöglichen.

## Executive summary

This report assesses Switzerland's winter electricity supply in 2050 across six scenarios developed by Axpo and examines how these portfolios interact with alternative European energy system configurations. The analysis is motivated by the *winter gap* in Switzerland, an existing seasonal mismatch between electricity demand and domestic supply that is expected to become more pronounced under current transition pathways.

It is important to note that this study does not assess the underlying decisions, assumptions, or policy rationales that led to the definition of the analyzed scenarios. These scenarios are treated as exogenous inputs. The purpose of the analysis is instead to provide a transparent, quantitative, and independent assessment of their implications.

The scenarios are evaluated along several key dimensions, including structural adequacy, market-driven dispatch, the role of hydropower and seasonal storage, the contribution of renewable generation, the need for dispatchable capacity, the value of flexibility options, and the influence of market integration and cross-border exchanges. This approach enables a consistent comparison of long-term system performance and highlights the main drivers of winter security of supply.

The results are conditional on the specific modeling assumptions, input data, and boundary conditions adopted in this study. They should therefore not be interpreted as forecasts or predictions, but rather as illustrative of system behavior under defined conditions.

The findings are intended to support comparative assessment and informed decision-making by highlighting key trade-offs, sensitivities, and structural drivers of winter supply security.

A central contribution of the study is to distinguish between two different concepts that are often conflated in discussions of winter security of supply. The first is winter net imports, which reflect the realized outcome of economically efficient cross-border trade in an integrated European market. The second is *winter import exposure*, which measures the structural dependence on imports, defined as the minimum volume of electricity imports required to meet winter demand. This distinction is essential because high winter imports do not necessarily imply inadequate domestic resources; they may simply reflect economically attractive imports from neighboring countries.

The analysis is based on hourly economic dispatch simulations using FEN's FlexECO model. Six Swiss scenarios are considered, each reflecting a different energy portfolio, and are combined with two potential evolution pathways of the European energy system: an Axpo reference case and a TYNDP-based scenario with higher renewable penetration. Two operating modes are applied: (i) *a market-integrated mode* with unconstrained trade (subject to transfer limits), and (ii) *a quasi-autarky benchmark* where Swiss electricity exports are disabled and electricity imports to Switzerland are restricted to last-resort use. This dual framework separates market-driven outcomes from structural winter adequacy.

The results show that all six Swiss scenarios analyzed in this study are able to limit structural winter import exposure to 5 TWh under the quasi-autarky benchmark. Under the assumptions of the study, this indicates that the proposed portfolios contain sufficient domestic resources to meet winter demand with only limited dependence on imports. However, in the market-integrated simulations, Switzerland imports substantially more in winter in all scenarios, while it exports during the summer. This is not a contradiction. Rather, it shows that winter net imports are strongly shaped by electricity prices and European system conditions. Switzerland tends to import when foreign electricity is cheaper, even if domestic capacity is available. Therefore, net imports alone are not a reliable indicator of winter adequacy.

Hydropower emerges as one of the key pillars of Swiss winter security of supply. Reservoir hydro provides a large seasonal shift of energy from summer to winter, in the order of 7 TWh/a under the modeled assumptions. This seasonal transfer is observed not only in the quasi-autarky simulations, where it directly supports adequacy, but also in the market-integrated simulations, indicating that it is economically attractive as well. In other words, storing water in summer and using it in winter is both valuable for winter adequacy and economically viable. At the same time, reservoir hydro also provides substantial short-term flexibility. When low-cost imports are available from Europe, hydro generation is reduced to preserve water, while hydro production is increased during periods of (Europe-wide) electricity scarcity, often supporting exports. Swiss reservoir hydro therefore acts both as a seasonal adequacy resource and as a flexibility interface with the European system.

Pumped hydro storage contributes primarily through short-term balancing, absorbing surplus electricity and generating during higher-value periods. While the model indicates that PHS can also contribute to longer-term shifting of energy, this should be interpreted as technical potential rather than an established operational pattern.

Additional flexibility from batteries and demand-side response has limited influence on seasonal import patterns and the winter energy balance when Switzerland is well integrated with the European system. Under more constrained conditions, these resources can support winter supply by reducing temporal mismatches between generation and demand, particularly in scenarios with high shares of renewables (especially solar). However, within the scope of this study, their contribution to maintaining the targeted level of winter adequacy appears limited.

The scenarios also highlight structural differences between solar and wind generation. Solar-heavy portfolios create pronounced daily mismatches and large summer surpluses that cannot be fully shifted to winter with available storage, leading to curtailment when export options are constrained. Wind generation is more evenly distributed over time and contributes relatively more in winter, thereby reducing seasonal imbalances and supporting adequacy.

Dispatchable generation, particularly gas-fired plants and nuclear, proves to be essential for limiting winter import exposure. Without dispatchable capacity, the system cannot remain below the 5 TWh benchmark under the study assumptions. However, utilization patterns differ under market integration: gas plants operate mainly during scarcity periods and exhibit low full-load hours, while nuclear plants run at high utilization year-round and also support electrolysis, storage, and exports. This underscores a key trade-off: dispatchable capacity may be necessary for adequacy but, depending on the resource which provides it, only intermittently used in an efficient market environment.

The evolution of the European energy system significantly affects the operation of the Swiss assets. In the TYNDP-based scenario with higher renewable capacity, Switzerland imports more frequently due to greater availability of low-cost electricity abroad. Conversely, reduced cross-border transfer capacity (between Switzerland and its neighboring countries) increases reliance on domestic dispatchable generation and dampens arbitrage-driven hydro operation. Adequacy and import dependence must therefore be assessed jointly with assumptions about European market development and integration.

Sensitivity analysis based on a nodal representation of the Swiss transmission grid, as opposed to a simplified copperplate representation, shows that internal constraints moderate peak flows and smooth dispatch patterns but do not materially alter the main dispatch pattern. The system-level roles of hydropower, renewables, and dispatchable capacity remain robust, suggesting that a single-node representation of the Swiss electricity system (copperplate modeling) is sufficient for the purposes of this study.

Overall, Switzerland's winter electricity challenge is not simply a question of domestic capacity. It is a system-level issue shaped by the interaction of generation portfolios, hydropower-based flexibility, dispatchable resources, and European market dynamics. While all six scenarios considered in this study can limit structural import exposure to the target level, actual winter imports are likely to remain higher whenever market conditions favor imports. Adequacy assessments should therefore move beyond net import metrics and incorporate structural exposure alongside a broader system perspective.

Future work should extend the analysis to include uncertainty in weather and outages, a more detailed representation of hydropower cascades and operational constraints, improved modeling of European market design and sector coupling, and a more realistic treatment of batteries, demand response, and network constraints under operational uncertainty. These extensions would support a more comprehensive and operationally grounded assessment of Switzerland's future winter security of supply.

# 1 Introduction

## 1.1 Motivation

Electric power systems across Europe are undergoing a profound transformation driven by decarbonisation policies, electrification of end uses, and the rapid deployment of renewable energy technologies. Switzerland is part of this transition and undertakes similar structural changes in its electricity system. Electrification of heating, transport, and industry is expected to increase electricity demand, while the gradual retirement of conventional generation technologies and the expansion of variable renewable resources are reshaping the generation mix. These developments introduce new operational dynamics and amplify existing structural characteristics of the Swiss power system.

One of the most prominent challenges is the so-called *winter gap*. Switzerland historically experiences a seasonal imbalance between electricity supply and demand, originally driven by lower hydropower inflows during winter due to hydrological conditions. This gap is now being exacerbated, and is expected to continue to widen, due to the proliferation of solar photovoltaic generation, which is strongly seasonal and concentrated in summer. As a consequence, Switzerland typically relies on net electricity imports during winter to balance supply and demand.

In the context of Swiss energy policy, limiting the winter gap has become an explicit objective. Current policy discussions often refer to a benchmark according to which Switzerland should aim to keep the winter gap, defined as the maximum acceptable net electricity import in winter, below approximately 5 TWh [1]. This threshold is not derived from a strict mathematical formulation, but rather represents a normative political target. While this threshold does not eliminate the need for cross-border trade, it reflects the intention to ensure that the Swiss electricity system retains sufficient domestic capacity and flexibility to maintain winter supply security even under less favorable market conditions.

However, within an interconnected European electricity market, winter imports do not automatically signal a systemic vulnerability. Cross-border trade allows Switzerland to import electricity during periods of scarcity and export when domestic production exceeds demand. In such a setting, cross-border exchanges primarily reflect the outcome of economically optimal dispatch across countries rather than a purely physical dependence on foreign supply. Switzerland may therefore import electricity even when domestic resources would in principle be sufficient to cover demand, simply because importing is economically advantageous.

Nevertheless, this equilibrium depends on efficient access to the broader European market. The challenge of the winter gap can shift from a matter of economics to a security of supply concern if trades with European countries are perturbed, whether by technical grid constraints, political shifts, or energy shortages across the continent.

For this reason, the interpretation of the winter gap requires a distinction between two related but conceptually different indicators. The first is *winter net imports*, which represent the realized market outcome in an interconnected electricity system and reflect the interaction between domestic generation, cross-border price signals, and European system conditions. The second is *winter import exposure*, which represents the structural reliance on imports, defined as the minimum volume of electricity imports required to meet winter demand. In contrast to winter net imports, winter import exposure captures an adequacy-oriented perspective and measures the potential dependence on external electricity supply rather than the outcome of cross-border trading.

Distinguishing between these two concepts is important because they can lead to different conclusions regarding security of supply. High net imports during winter may simply reflect economically efficient electricity trading, while high structural import exposure would indicate that domestic resources may be insufficient to cover winter demand without significant reliance on external supply. A meaningful assessment of Switzerland's winter supply situation therefore requires considering both perspectives simultaneously.

The evolution of the Swiss electricity system can further impact this assessment. Different generation portfolios influence both the seasonal balance of electricity production and the flexibility of system operation. In particular, hydropower plays a dual role in Switzerland: reservoir hydro provides seasonal storage by shifting water inflows from summer to winter, while both reservoir and pumped storage plants provide short-term flexibility and enable cross-border arbitrage. At the same time, increasing renewable penetration across Europe and potential changes in market integration may alter electricity price patterns, cross-border flows, and the economic conditions under which Swiss resources operate.

As a result, analyzing Switzerland's winter supply situation requires a system-wide perspective that considers both domestic generation portfolios and interactions with the broader European electricity system. In particular, it is necessary to distinguish structural adequacy considerations from market-driven operational outcomes and to evaluate how Swiss flexibility resources interact with European supply patterns.

## 1.2 Objectives

The primary objective of this study is *to evaluate Switzerland's winter electricity supply under a range of long-term energy scenarios and to assess how different generation portfolios interact with the European electricity system*.

The analysis focuses on six alternative scenarios for Switzerland in 2050 developed by Axpo, each representing a distinct portfolio of power generation technologies (specifically, different combinations of installed capacities of nuclear, gas, solar, and wind generation) designed to provide sufficient domestic capacity while reflecting different strategic technology pathways.

To capture the influence of the broader European context, the Swiss scenarios are analyzed in combination with two alternative representations of the European electricity system: a European reference scenario based on Axpo assumptions and a scenario derived from the Ten-Year Network Development Plan (TYNDP) developed by ENTSO-E and ENTSO-G [2, 3]. These combinations allow the study *to examine how changes in the European generation mix and market conditions influence Swiss dispatch patterns, cross-border electricity exchanges, and seasonal supply adequacy*.

A key methodological element of the study is the comparison between two operational perspectives.

- First, Switzerland is analyzed under *market-integrated conditions*, where cross-border electricity exchanges occur freely subject to transfer capacity constraints and reflect economically optimal dispatch across Europe.
- Second, a stylized *quasi-autarky* benchmark is introduced, in which imports are available only as a last-resort option and exports are disabled. This benchmark isolates the adequacy dimension of the problem and allows structural winter import exposure to be evaluated independently from market-driven trading outcomes.

Within this framework, the study pursues four main objectives:

1. To clarify the interpretation of Switzerland's winter gap by distinguishing between structural winter import exposure and market-driven winter net imports.
2. To assess whether the six Axpo scenarios provide sufficient domestic resources to limit structural winter import exposure under the assumed future conditions.
3. To analyze how key assets and resources support seasonal adequacy and short-term balancing in different scenarios.
4. To evaluate how European system evolution and market integration influence Swiss dispatch patterns, cross-border electricity exchanges, and the utilization of domestic generation technologies.

Rather than identifying a single preferred pathway, the goal of this study is *to provide a transparent operational assessment of the proposed scenarios and to clarify the mechanisms that drive the observed outcomes*.

By analyzing the interaction between domestic portfolios, flexible assets, renewable generation, and European market conditions, the report aims to provide a structured basis for interpreting Switzerland's future winter electricity supply situation.

# 2 Methodology

## 2.1 Model overview

To explore how the Swiss energy system operates under the considered range of scenarios, we employ the linear economic dispatch model implemented in FlexECO, FEN's in-house tool for multi-energy system analysis [4].

In this project, system operation is represented through a cost-minimizing linear optimization framework. The model determines the least-cost dispatch of all available resources over a full year while satisfying energy demand and respecting technical and operational constraints. The objective is to identify an hourly operational schedule that meets electricity and energy service requirements at minimum total system cost, representing a simplified coupled European wholesale electricity market.

Within this framework, energy technologies and assets are dispatched to minimize total system costs. Under standard market assumptions, this cost-minimizing dispatch corresponds to welfare maximizing operation of the power system.

## 2.2 Mathematical formulation

Mathematically, the problem is formulated as the following linear program:

$$\begin{aligned} \min_{x \in \mathbb{R}^n} \quad & c^\top x \\ \text{s.t.} \quad & Ax \leq b \end{aligned} \tag{1}$$

where $c$ is the vector of linear cost coefficients, $A$ is the constraint coefficient matrix, and $b$ is the corresponding constraint parameter vector. The decision variable vector $x$ contains all relevant operational variables for each time step, including electricity generation, load served, energy curtailment, load shedding, energy flows, storage charging and discharging, and ramping actions.

The constraint set captures energy balance, capacity limits, ramping limits, and network restrictions. Together, these constraints ensure that the resulting dispatch is physically feasible and consistent with system operation.

## 2.3 Model assumptions

The following main assumptions are considered within this study:

- Europe is modeled in an aggregated manner, with each country represented as a single copperplate node. Switzerland is also represented as a single copperplate node; however, a nodal representation of Switzerland is also considered for selected analyses.
- Each simulation covers a full year with hourly temporal resolution.
- Perfect foresight is assumed, meaning that future demand, renewable capacity factors, and hydro inflows are known with certainty over the entire optimization horizon.
- Cross-border electricity exchanges are constrained using net transfer capacities (NTCs). Flow-based market coupling is not considered.

- Unit commitment decisions (on/off status, minimum up/down times, start-up and shut-down costs) are not modeled. However, linear ramping constraints are included in order to avoid unrealistic changes in generation between consecutive hours (notably for nuclear technologies).
- In the nodal representation of Switzerland, a DC power flow approximation is applied to represent internal transmission constraints.
- The initial and final state of charge of storage technologies are constrained to be equal to prevent artificial energy gains over the simulation horizon. The initial level is optimized endogenously by FlexECO.

## 2.4 Simulations

As mentioned in the previous section, assessing Switzerland's winter gap requires distinguishing between two complementary metrics: winter net imports and winter import exposure. To isolate and assess these concepts, two distinct simulation settings are employed.

- Market-integrated simulations: This setting represents standard operation within a fully coupled European electricity market. Cross-border exchanges between Switzerland and neighboring countries are allowed within transfer capacity limits, and dispatch is determined through system-wide cost minimization. The resulting net imports reflect economically efficient trade flows and therefore capture realized market outcomes rather than structural import dependency.
- Quasi-autarky simulations: This setting is used to assess structural winter import exposure. Electricity exports from Switzerland to neighboring countries are disabled, while imports are permitted only at prohibitively high cost, effectively representing the last option before load shedding. By suppressing economically motivated trades, this configuration reveals the structural reliance on electricity imports and allows to assess the winter import exposure.

## 2.5 Limitations

With respect to key performance metrics, this report bases its analysis on Switzerland's net electricity imports, complemented by a broader evaluation of dispatch dynamics and the operational behaviour of the Swiss energy system.

This study does not assess the underlying investment decisions, assumptions, or policy rationales that led to the definition of the analyzed scenarios, which are treated as exogenous inputs.

# 3 Input data and scenarios

This section summarizes the key data, scenario definitions, and assumptions used in the project.

## 3.1 Swiss scenario definitions

The project is based on six scenarios developed by Axpo. These scenarios were primarily designed to ensure sufficient domestic generation capacity, limiting Switzerland's winter import dependency to approximately 5 TWh by 2050, while reflecting a range of political contexts and policy frameworks. Cost minimization was not the primary objective in their construction. The resulting scenarios differ in their energy mixes: four scenarios are structured around a single dominant technology, while the remaining two assume a more diversified energy mix. The scenarios are summarized below:

- **Nuclear-focus:** Deployment of new nuclear capacity to replace retiring plants and provide reliable baseload generation.
- **Gas-focus:** Construction of new gas-fired power plants providing flexible and dispatchable generation capacity.
- **Solar-focus:** Large-scale expansion of photovoltaic capacity, making solar the primary electricity source.
- **Wind-focus:** Significant deployment of onshore wind power.
- **Renewables + gas:** Combination of expanded renewable generation (solar and wind) with new gas-fired plants providing backup capacity. In the remainder of this report, this scenario will be referred to as *RES+Gas*.
- **Coexistence:** Diversified system in which nuclear, renewable generation, and flexible thermal capacity coexist.

Figure 3.1.1 and Table 3.1.1 present the installed generation capacities in 2050 for each scenario. The technology-led cases show comparatively high installed capacity for the technology that gives the scenario its name. In contrast, the mixed portfolios distribute capacities more broadly: the Coexistence scenario combines a small nuclear fleet with substantial solar and wind deployment, while the RES+Gas scenario relies mainly on solar and wind.

A common feature of the scenarios with high renewable energy shares (Solar-focus, Wind-focus, and RES+Gas) is also the significant presence of gas-fired generation capacity, which provides dispatchable flexibility and adequacy during periods of low renewable output. Installed gas capacity[1] reaches 2.4 GW, 2.8 GW, and 1.4 GW in the Solar-focus, Wind-focus, and RES+Gas scenarios, respectively. Nuclear capacity is only available in the Nuclear-focus and Coexistence scenarios, which assume 3.3 GW and 2.2 GW of installed nuclear capacity, respectively. The Gas-focus scenario assumes the highest amount of installed gas-fired capacity, reaching around 4 GW.

Storage assumptions are derived primarily from the TYNDP data package. In its original form, the TYNDP dataset distinguishes between reservoir hydro, pumped hydro with inflow (open pumped hydro storage), and pumped hydro without inflow (closed pumped hydro storage). In order to enable

[1] This aggregated capacity includes old existing plants, new conventional power plants, and new power plants equipped with carbon capture and storage (CCS) technologies.

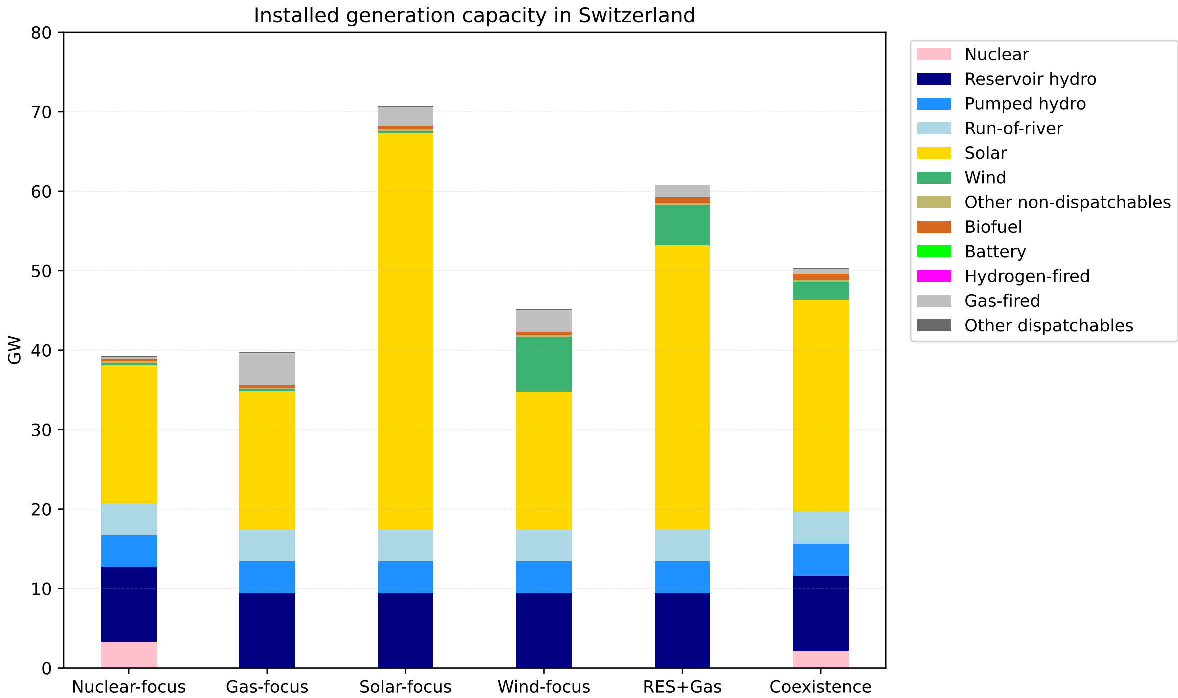



Figure 3.1.1: Installed generation capacity in Switzerland in 2050 in the six Axpo scenarios.

Table 3.1.1: Installed generation capacity assumptions for Switzerland by technology and scenario (GW).

| Technology | Nuclear-focus | Gas-focus | Solar-focus | Wind-focus | RES+Gas | Coexistence |
|---|---|---|---|---|---|---|
| **Non-dispatchable generation** | | | | | | |
| Run-of-river | 4.02 | 4.02 | 4.02 | 4.02 | 4.02 | 4.02 |
| Solar | 17.34 | 17.34 | 49.91 | 17.34 | 35.74 | 26.70 |
| Wind | 0.25 | 0.25 | 0.25 | 6.89 | 5.07 | 2.20 |
| Other non-dispatchables | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 | 0.25 |
| **Total non-dispatchable** | **21.86** | **21.86** | **54.43** | **28.50** | **45.08** | **33.17** |
| **Dispatchable generation** | | | | | | |
| Nuclear | 3.30 | – | – | – | – | 2.20 |
| Biofuel | 0.36 | 0.36 | 0.36 | 0.36 | 0.82 | 0.82 |
| Gas-fired | 0.22 | 4.02 | 2.42 | 2.82 | 1.42 | 0.62 |
| Hydrogen-fired | – | – | – | – | – | – |
| Other dispatchables | – | – | – | – | – | – |
| **Total dispatchable** | **3.88** | **4.38** | **2.78** | **3.18** | **2.24** | **3.64** |
| **Storage technologies** | | | | | | |
| Reservoir hydro | 9.46 | 9.46 | 9.46 | 9.46 | 9.46 | 9.46 |
| Pumped hydro | 3.98 | 3.98 | 3.98 | 3.98 | 3.98 | 3.98 |
| Batteries | – | – | – | – | – | – |
| **Total storage** | **13.44** | **13.44** | **13.44** | **13.44** | **13.44** | **13.44** |
| **Total installed capacity** | **39.18** | **39.68** | **70.65** | **45.12** | **60.76** | **50.25** |

a more transparent interpretation of hydro storage behaviour, we adopt a simplifying reclassification: all pumped hydro plants are modeled as pumped hydro without inflow, and the corresponding inflows are reassigned to reservoir hydro. This decouples reservoir and pumped hydro operations and improves the interpretation of storage behaviour, in particular by separating seasonal energy shift (reservoir hydro driven by inflow availability) from short-term flexibility (pumped hydro driven by price spreads and system needs). When pumped hydro is modeled with inflow, it becomes difficult to distinguish whether seasonal stored energy originates from natural inflow or from pumping cycles, which complicates the assessment of seasonal storage value. The resulting storage power and energy capacities are reported in Table 3.1.2. Batteries are not included in the base scenarios and are evaluated separately in a dedicated sensitivity case.

Table 3.1.2: Assumed hydro storage capacities in Switzerland in 2050.

| **Technology** | **Storage capacity [TWh]** |
|---|---|
| Reservoir hydro | 8.38 |
| Pumped hydro | 1.50 |

On the demand side, Swiss final electricity demand is assumed identical across scenarios, as shown in Figure 3.1.2. Total annual demand is set to approximately 78 TWh/a for end uses (conventional, heating, and electromobility) plus 9 TWh/a of electricity demand for electrolysis.

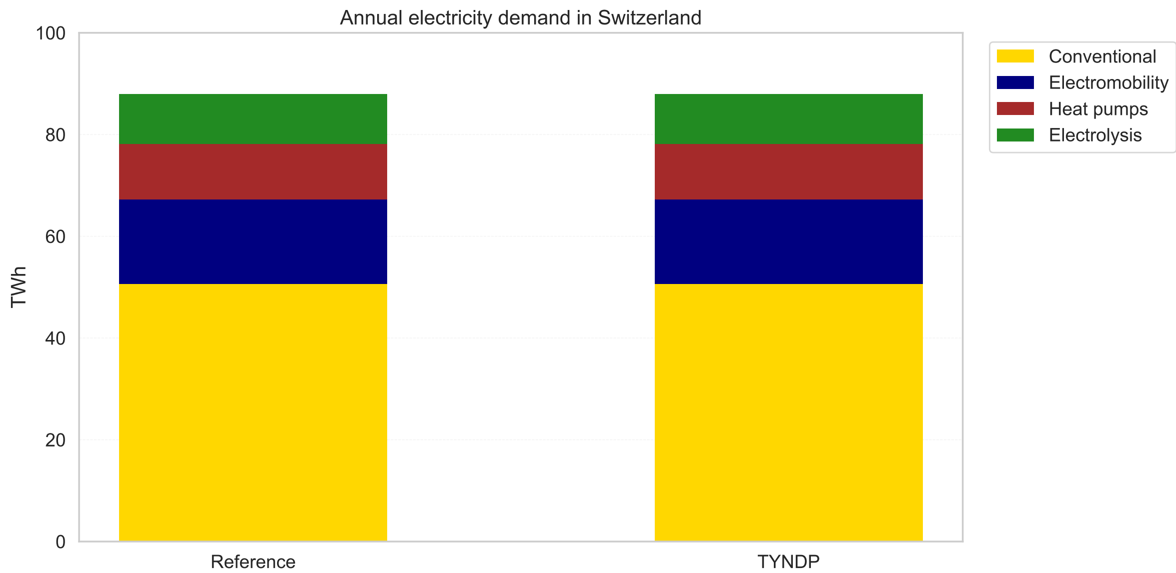



Figure 3.1.2: Final annual electricity demand in Switzerland in 2050 in the six Axpo scenarios.

To provide a simple comparison of the potential domestic winter energy available across the six Swiss scenarios, we derive an indicative estimate of winter usable energy from the main domestic resources. The calculation aggregates the winter contribution of hydropower, renewable generation, and dispatchable technologies under a consistent set of assumptions summarized in Table 3.1.3. Reservoir hydro is assumed to be able to deliver approximately 10.4 TWh during winter, based on 3.3 TWh of winter inflow and the usable share of installed storage capacity. Run-of-river generation is approximated at about one third of its annual inflow (5.45 TWh). Solar generation is assumed to produce one third of its annual energy during winter months, while wind generation is estimated using the assumed annual capacity factor. Nuclear generation, where present, is assumed to operate at 100% capacity factor over the winter period, and gas-fired and biofuel plants are treated as fully available over winter months. Pumped hydro and batteries are not considered as net energy sources.

Under these assumptions, the indicative domestic winter energy potential ranges from about 39.56 TWh in the Nuclear-focus scenario to about 44.99 TWh in the Solar-focus scenario, with intermediate values of 41.74 TWh (Gas-focus), 44.50 TWh (Wind-focus), 43.84 TWh (RES+Gas), and 43.64 TWh (Coexistence), as reported in Table 3.1.4. The higher values above 43 TWh are observed in scenarios with large amounts of installed renewable capacities (Solar-focus, Wind-focus, RES+Gas, Coexistence), which increase total annual energy production even if only a fraction of that energy is generated during winter. By contrast, the Nuclear-focus and Gas-focus scenarios rely more heavily on dispatchable technologies with comparatively smaller renewable installations, leading to lower overall annual energy volumes and therefore lower indicative winter energy contributions under this simplified calculation.

Given an estimated winter demand of approximately 45 TWh (excluding electrolysis, which is assumed to be fully flexible across the year), most scenarios appear broadly balanced in energy terms. The Nuclear-focus scenario falls slightly short of this benchmark. However, this gap should be interpreted with caution. First, part of the deficit can be covered by additional intra-seasonal shifting through storage (pumped hydro storage), which is not accounted for as a net energy source in this approximation. Second, the lower winter energy in the Nuclear-focus case reflects the overall design of the scenario, characterized by limited total annual energy from non-nuclear sources, rather than an intrinsic limitation of nuclear generation itself.

These values should nevertheless be interpreted as indicative energy potentials rather than firm adequacy levels. In particular, the estimate does not account for outages, maintenance schedules, fuel supply constraints, hydrological and metereological variability, internal transmission constraints within Switzerland, or the hourly matching between generation and demand.

As a result, while the approximation provides a useful comparison of the overall winter energy content of the scenario portfolios, it cannot substitute for a detailed operational or adequacy assessment based on hourly system simulations. Such a detailed assessment, accounting for the full temporal dynamics of the system and operational constraints, is presented later in the results section.

Table 3.1.3: Main assumptions used to approximate domestic winter energy potential in Switzerland.

| **Parameter** | **Assumption** |
|---|---|
| Weather year | 2009 |
| Winter period | October–March (4368 hours) |
| Winter demand | 45 TWh |
| Reservoir hydro winter inflow | 3.3 TWh |
| Usable reservoir storage | 85% of 8.38 TWh (7.1 TWh seasonal shift) |
| Reservoir hydro winter energy | $\approx$ 10.4 TWh |
| Run-of-river generation | $\approx$ 1/3 of annual energy produced in winter |
| Solar generation | $\approx$ 1/3 of annual energy produced in winter |
| Wind generation | $\approx$ 60% of annual energy produced in winter |
| Nuclear generation | Fully available over winter hours |
| Gas and biofuel generation | Fully available over winter hours |
| Other non-dispatchables | $\approx$ 50% of annual energy produced in winter |
| Storage technologies (PHS, batteries) | Not treated as net energy sources |

Table 3.1.4: Indicative domestic winter energy potential across the six Swiss scenarios.

| Scenario | Approx. usable winter energy [TWh] |
|---|---|
| Nuclear-focus | 39.56 |
| Gas-focus | 41.74 |
| Solar-focus | 44.99 |
| Wind-focus | 44.50 |
| RES+Gas | 43.84 |
| Coexistence | 43.64 |
| **Range across scenarios** | **39.56–44.99** |

## 3.2 European system assumptions

The Swiss scenarios are merged with two European scenarios: (i) an Axpo European reference scenario (referred to as "Reference"), and (ii) a European scenario based and adapted from the TYNDP Global Ambition scenario developed by ENTSO-E and ENTSO-G (referred to as "TYNDP") [2, 3]. Specifically, the TYNDP scenario is based on the Global Ambition pathway available in the TYNDP 2024 data package. Installed European generation capacities in 2050 for both cases are shown in Figure 3.2.1 and Table 3.2.1. More detailed assumptions on these scenarios are available in Appendix A.

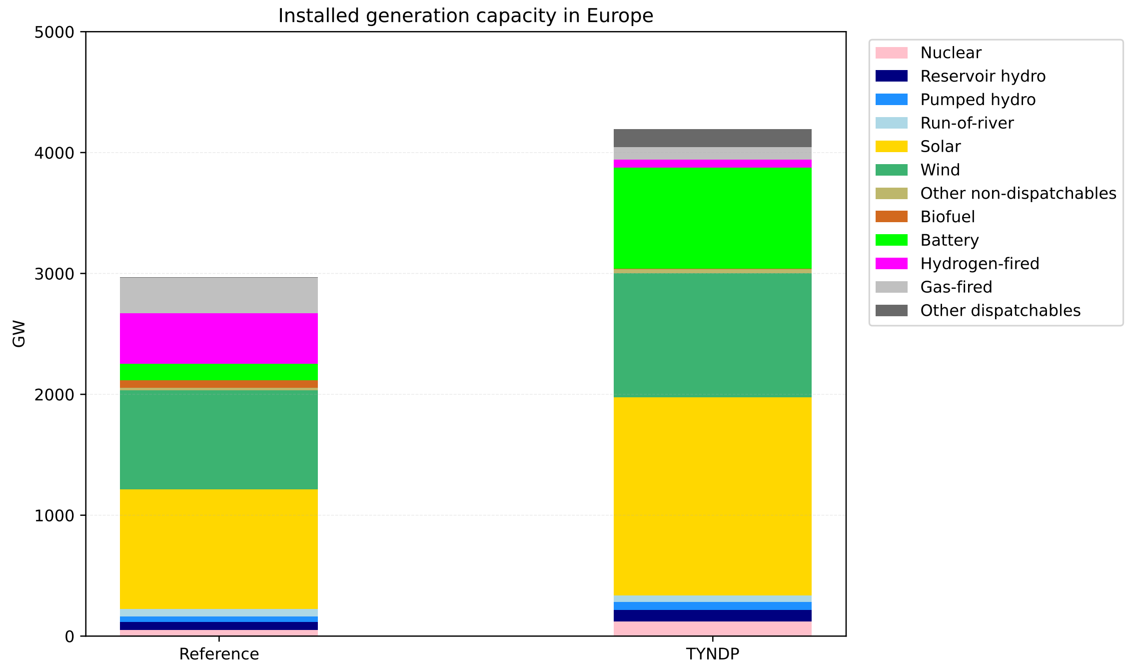



Figure 3.2.1: Installed generation capacity in Europe in 2050 in the reference Axpo scenario and the selected TYNDP scenario.

The reference scenario combines significant renewable capacity and hydrogen-fired and gas-fired dispatchable capacity, while the TYNDP scenario assumes an even wider expansion of renewables (particularly solar), higher nuclear capacity, but limited hydrogen-fired and gas-fired dispatchable capacity. Overall, the total dispatchable capacity is higher in Reference scenario.

Figure 3.2.2 reports total European final electricity demand and the electricity demand associated with electrolysis.

In both European scenarios, non-electrolysis electricity demand (conventional, heating, and electro-mobility combined) is the range of 4700-4900 TWh/a. The main difference consists in the assumed electrolysis target, which reaches around 436 TWh/a in the reference scenario and exceeds 2,100 TWh/a in the TYNDP scenario. In this study, electrolysis is represented as a flexible demand target, i.e. it is supplied only when low-cost surplus electricity is available (for example during high renewable output periods; see Appendix A for more details). The aim is to capture flexible hydrogen production through electrolysis rather than enforcing fixed hydrogen production targets.

Table 3.2.1: Assumed installed generation capacities in Europe in 2050 by technology and scenario (GW).

| Technology | Reference | TYNDP |
|---|---|---|
| **Non-dispatchable generation** | | |
| Run-of-river | 61.10 | 54.03 |
| Solar | 987.89 | 1638.84 |
| Wind | 823.65 | 1026.71 |
| Other non-dispatchables | 18.12 | 33.65 |
| **Total non-dispatchable** | **1890.76** | **2753.23** |
| **Dispatchable generation** | | |
| Nuclear | 52.84 | 121.37 |
| Biofuel | 63.77 | 2.97 |
| Gas-fired | 295.89 | 104.92 |
| Hydrogen-fired | 418.47 | 65.17 |
| Other dispatchables | 0.50 | 146.73 |
| **Total dispatchable** | **831.47** | **441.16** |
| **Storage technologies** | | |
| Reservoir hydro | 64.46 | 97.32 |
| Pumped hydro | 46.34 | 65.13 |
| Batteries | 134.55 | 835.77 |
| **Total storage** | **245.35** | **998.22** |
| **Total installed capacity** | **2967.58** | **4192.61** |

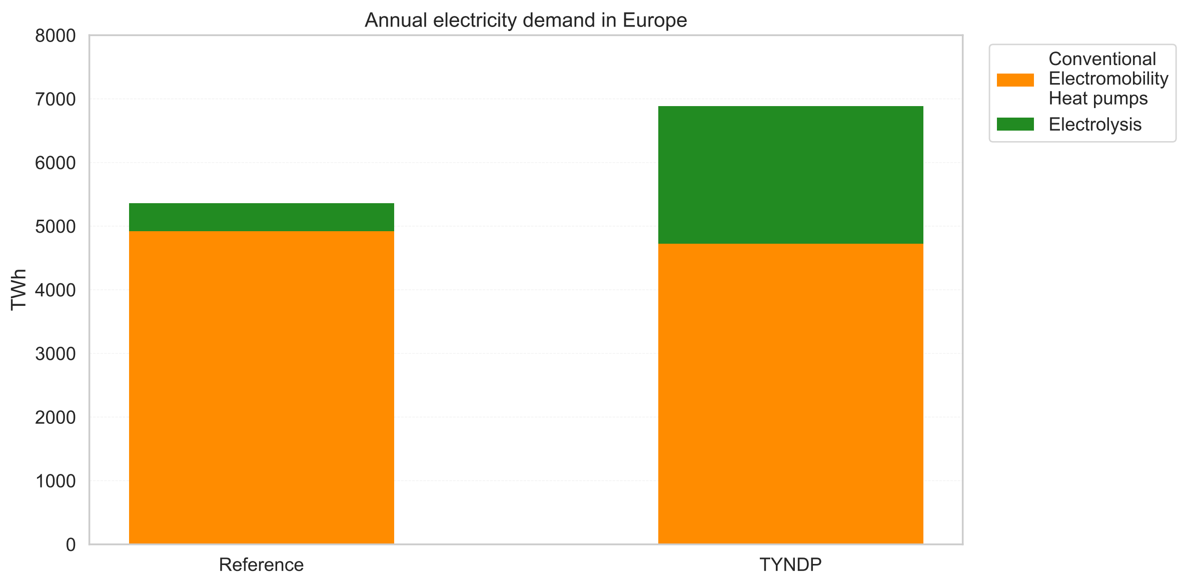



Figure 3.2.2: Final annual electricity demand in Europe in 2050 in the reference Axpo scenario and the selected TYNDP scenario.

## 3.3 Cross-border capacities

Cross-border transfer capacities are aligned across the two European scenario using the TYNDP assumptions to ensure consistency in the representation of interconnection limits. The resulting Swiss interconnection capacities are listed in Table 3.3.1.

Table 3.3.1: Electricity cross-border transfer capacities between Switzerland and neighboringring countries in 2050 used in this study [MW].

| CH→DE | DE→CH | CH→FR | FR→CH | CH→IT | IT→CH | CH→AT | AT→CH |
|---|---|---|---|---|---|---|---|
| 4969 | 5669 | 3200 | 5500 | 5772 | 3110 | 1200 | 1200 |

### 3.4 Time series and weather assumptions

Time series for electricity demand, renewable capacity factors, and hydro inflows are taken from the TYNDP data package and adapted to match the specific assumptions of the project. The analysis considers the three weather years available in TYNDP, namely 1995, 2008, and 2009, to capture inter-annual variability, but focusing mainly on the weather year 2009. To integrate Axpo-specific expectations for Switzerland (in all Swiss scenarios) and for Europe (in the European reference scenario), we apply an ad-hoc recalibration: annual energy inflow for Swiss reservoir hydro and run-of-river and renewable capacity factors are scaled to Axpo assumptions (see Tables 3.4.1 and 3.4.2 for hydro inflows and renewable capacity factors in Switzerland), while the hourly profile is retained from the TYNDP data. For the TYNDP scenario at European level, we maintain the original profiles also in terms of magnitude.

Table 3.4.1: Assumed hydro inflow in Switzerland.

| Technology | Inflow [TWh] |
|---|---|
| Reservoir hydro | 20.3 |
| Run-of-river | 17.2 |

Table 3.4.2: Assumed renewable capacity factors in Switzerland.

| Technology | Annual capacity factor [%] |
|---|---|
| Solar PV - Rooftop | 10.3 |
| Solar PV - Ground mounted | 10.8 |
| Solar PV - Alpine | 17.1 |
| Wind | 22.5 |

This ensures consistency with Axpo's long-term assumptions for Swiss and European renewable and hydro production and avoids overly optimistic capacity factors for solar and wind technologies from using unadjusted TYNDP profiles [2].

### 3.5 Economic and additional assumptions

Fuel and carbon price assumptions, reported in Table 3.5.1, are based on assumptions provided by Axpo and complemented with data adapted from the TYNDP data package [2]. Remaining techno-economic inputs, such as efficiencies and variable operating costs, are based on previous projects conducted at FEN [6, 7, 8] and supplemented with additional sources [9].

Additional considered assumptions that can affect model outcomes are mentioned here:

- Heating and electromobility demand profiles are based on synthetic profiles developed specifically for this study. Unless stated otherwise, 20% of heating demand and 50% of electromobil-

[2] It should be noted that TYNDP profiles may differ from those reported in other sources, including publications by the Swiss Federal Office of Energy [5].

Table 3.5.1: Main assumed fuel and carbon costs.

| Fuel | Cost |
|---|---|
| Natural gas | 28.38 CHF/MWh |
| Uranium | 6.05 CHF/MWh |
| Hydrogen | 144.51 CHF/MWh |
| Biofuel | 62.18 CHF/MWh |
| Carbon tax | 191.12 CHF/t$CO_2$ |

ity demand are assumed to be flexible on a daily basis both in Switzerland and other European countries. See Appendix A for more details.

- Hydrogen-fired power plants should be interpreted as a representative proxy for future renewable gas-fired generation technologies. While hydrogen-fired plants are included in the model, the results are intended to be broadly applicable to plants using other synthetic or renewable gaseous fuels.
- The value of lost load (VoLL), i.e. the cost of load shedding, is assumed to be 4,000 CHF/MWh. For electrolysis, VoLL is assumed to be approximately 50 CHF/MWh, reflecting the estimated market value of hydrogen produced from 1 MWh of electricity. See Appendix A for more details.
- Electricity demand for electrolysis should be interpreted as a fully flexible demand target and is not included in the load shedding calculation. In Switzerland, the maximum electrolysis load that can be accommodated is assumed to slightly exceed 2.0 GW. This capacity would be sufficient to achieve the target annual electricity consumption for electrolysis with an average electrolyzer utilization rate of 50% throughout the year.
- Linear ramping costs are estimated based on redispatch cost data available in [9].
- New power plants that are assumed to be present for providing reserve capacity are excluded from the analysis.
- In order to account for the effect of aggregation, the state of charge of reservoir hydropower plants in Switzerland is bounded between 10% and 95% of the maximum storage capacity.
- Nuclear plants are assumed to ramp up and down at 10% (a conservative assumption) of rated capacity per hour and to operate at an annual capacity factor of 90%. In the market-integrated scenarios, a minimum generation of 50% of rated power is also assumed. In the quasi-autarky setting, this last assumption is relaxed to avoid infeasibility issues in the optimization model.
- Fuel shortages and forced outages of generation units are not explicitly modeled.

# 4 Results and discussion

## 4.1 Overview

This section summarizes the main findings from the simulation-based assessment of the six AXPO scenarios and discusses their implications for Switzerland's winter security of supply. The analysis is based on hourly economic dispatch simulations of a pan-European system, complemented by targeted sensitivity analyses. The focus is not on long-term least-cost investment planning, but on operational outcomes and their interpretation under different sensitivity settings.

As discussed earlier, two main simulation settings are used in this study: (i) *a quasi-autarky simulation setting*, in which exports are disabled and imports are only available at prohibitively high cost, effectively representing a last-resort option before load shedding; (ii) *a market-integrated setting*, where Switzerland is fully coupled to the European electricity market, cross-border exchanges are allowed within transfer capacity limits, and dispatch is determined by system-wide cost minimization. A general overview of the simulation results using these two settings across the six Axpo scenarios is presented in Section 4.2.

As discussed earlier, the winter gap is assessed using two distinct concepts: *structural winter import exposure*, defined as the dependence on external imports during winter and evaluated using the quasi-autarky simulation setting, and *net electricity imports*, defined as the realized outcome of economically efficient cross-border trade and evaluated using the market-integrated simulation setting. These two metrics capture different dimensions of system performance and can lead to different conclusions. This distinction is examined in detail in Section 4.3.

A defining feature of the Swiss electricity system is its hydropower fleet. Hydropower provides low-carbon and relatively low-cost electricity while enabling both seasonal storage and short-term flexibility. Its role is examined in Sections 4.4-4.6. Additional flexibility options, such as battery storage systems and demand-side response, may complement hydropower in short-term balancing, and are discussed in Section 4.7.

Swiss dispatch patterns can change depending on the specific energy mix. Solar-dominated portfolios generate large summer surpluses and therefore require substantial flexibility and export capability to limit curtailment. Wind generation, by contrast, is better aligned with winter demand and tends to reduce seasonal imbalances. Dispatchable technologies, such as gas-fired and nuclear plants, shape system operation during periods of high residual demand, although their utilization also depends on generation patterns in the broader European system. These aspects are discussed in Sections 4.8 and 4.9.

Finally, the broader European energy transition and the degree of market integration strongly influence the operation of the Swiss electricity system. Differences between the European Reference and TYNDP scenarios can affect Swiss dispatch patterns and net imports. Similarly, reductions in cross-border transfer capacity (NTCs) tend to shift the system towards more domestically driven operation. Internal grid constraints, represented through a simplified nodal model for Switzerland can limit the responsiveness of hydropower and cross-border exchanges to external signals, thereby constraining flexibility and arbitrage potential. These aspects are assessed and discussed in Sections 4.10-4.12.

The remainder of this chapter develops these insights in more detail. Unless stated otherwise, results refer to weather year 2009. Each European country is modeled as a single node. Switzerland is also represented as a single node, except where a more detailed internal grid representation is applied (Section 4.12). The analysis further includes sensitivity cases with reduced NTCs, the addition of battery storage, and the removal of flexible demand.

In the following sections, the terms *summer* and *winter* follow the electrical definition: summer refers to the six-month period from April to September, and winter to the six-month period from October to March.

## 4.2 Simulation results

In this section, we provide an overview of the simulation results for Switzerland under both modeling settings. The aim is to highlight the main operational patterns and to identify key aspects that are examined in greater detail in the subsequent sections. Results are presented in terms of seasonal injections and withdrawals of electricity[3] for the market-integrated setting (Figure 4.2.1) and the quasi-autarky setting (Figure 4.2.2).

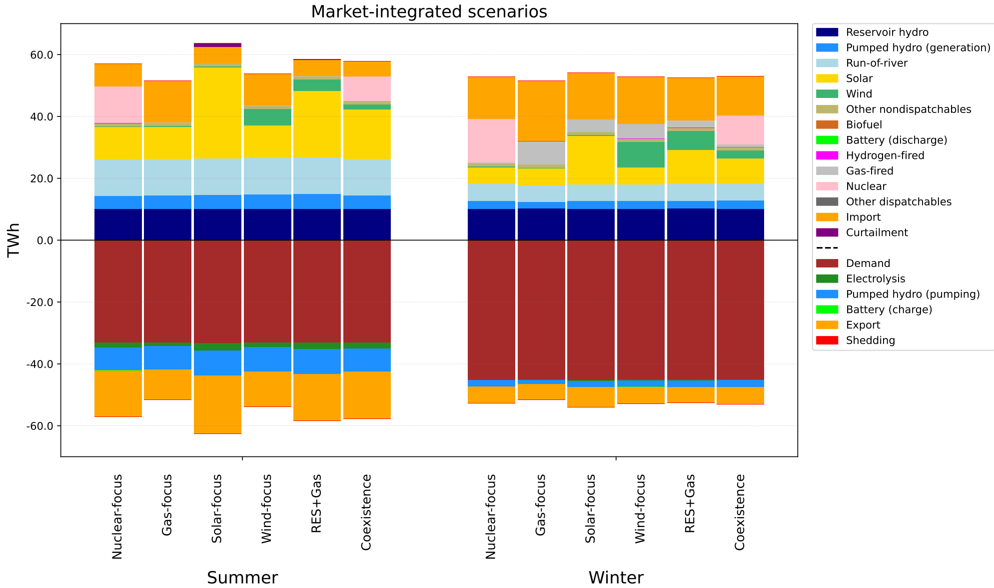



Figure 4.2.1: Seasonal electricity injections (positive values) and withdrawals (negative values) in Switzerland in the market-integrated simulations.

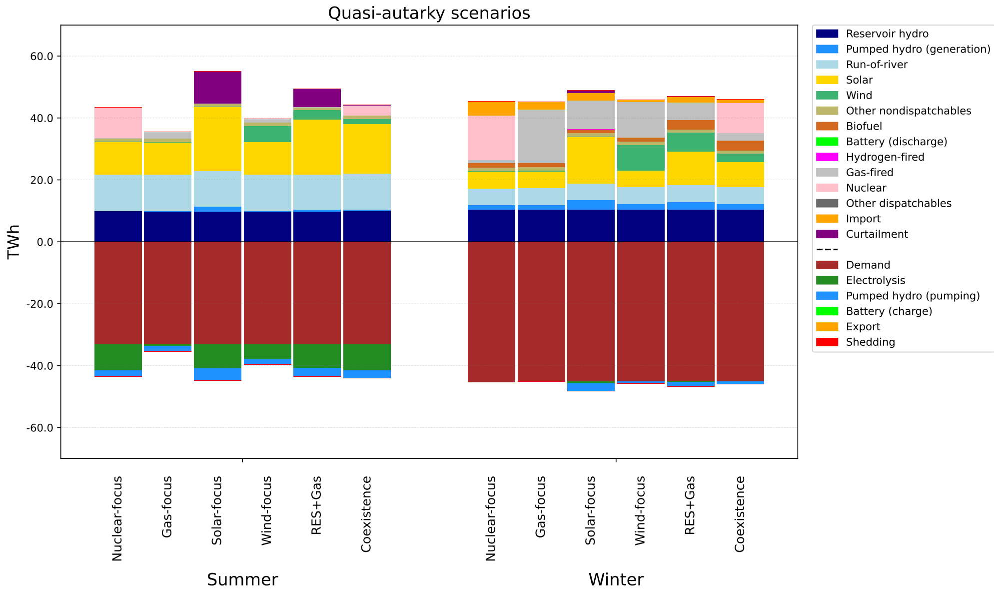



Figure 4.2.2: Seasonal electricity injections (positive values) and withdrawals (negative values) in Switzerland in the quasi-autarky simulations.

[3] Injections are positive values and correspond to generation, imports, and storage discharge; withdrawals are negative and correspond to demand, electricity consumption for electrolysis, storage charging, and exports.

In both settings, electricity demand (excluding electrolysis) is fully met in summer and winter, i.e. without the need for load shedding. Differences instead arise in the composition of withdrawals and the role of flexibility options. In the market-integrated setting, flexibility is primarily provided by pumped hydro storage, while other flexible loads play only a limited role. Under quasi-autarky conditions, the system relies more strongly on internal balancing, leading to a somewhat greater use of flexible demand to absorb surplus generation, particularly in renewable-dominated scenarios such as the Solar-focus case.

Overall, the contribution of electrolysis remains limited and falls short of the indicative Swiss target (approximately 9 TWh of electricity consumption) in both settings. This reflects the limited availability of sufficiently low-cost surplus electricity, both at the European level in the market-integrated setting and domestically under quasi-autarky conditions. In this modeling framework, electrolysis is treated as a fully flexible demand and is not included in the load shedding metric; it therefore acts as a residual sink for excess generation rather than a core driver of overall electricity demand.

On the generation side, hydropower constitutes the backbone of the system across all scenarios and settings, with broadly consistent seasonal patterns. Reservoir hydropower contributes approximately 10 TWh in both summer and winter, while run-of-river generation is concentrated in summer. The utilisation of pumped hydro varies by scenario but is significantly higher in the market-integrated setting, highlighting the added value of Swiss storage flexibility in the presence of cross-border trade.

Across scenarios, variations in renewable generation reflect installed capacities: solar output is concentrated in summer, while wind contributes more in winter.

Domestic generation is complemented by dispatchable sources, primarily nuclear and gas. In the market-integrated setting, nuclear generation (where available) operates at high output levels throughout the year, suggesting that summer production can be absorbed by the European system under the simulated conditions. Gas-fired generation is used mainly in winter due to its higher marginal cost. In contrast, under quasi-autarky conditions, nuclear output is reduced in summer, indicating that domestic demand and flexibility alone is insufficient to absorb full production in the absence of export opportunities. Gas generation increases in winter, and to a lesser extent in summer, to compensate for the lack of imports.

Generation curtailment patterns (mostly solar power curtailment) further illustrate the role of market integration. In the market-integrated setting, curtailment is limited and occurs mainly in summer in solar-dominated scenarios (Solar-focus and RES+Gas), where peak generation exceeds export capacity and/or often overlaps with peak production in neighboring countries. Under quasi-autarky conditions, curtailment increases markedly in summer, reflecting the inability to fully store or utilize excess solar generation domestically. Limited curtailment is also observed in winter in the Solar-focus scenario.

Finally, cross-border exchanges differ fundamentally between the two settings. The market-integrated setting exhibits substantial bidirectional trade, enabling efficient balancing across regions. By contrast, the quasi-autarky setting restricts exchanges to imports, primarily in winter, thereby highlighting Switzerland's structural reliance on external supply under constrained conditions.

### 4.3 Winter gap: structural exposure and net imports

This project focuses on the so-called *winter gap*: the mismatch between electricity production and consumption during winter in Switzerland. To design meaningful policies and investment strategies, it is essential to clarify what this gap truly represents, because different definitions can lead to different conclusions. The winter gap is often interpreted as net electricity imports over the winter period [1], typically defined as October to March. While this indicator is easy to understand and communicate, it can be misleading because it tends to blur the distinction between structural import dependence and market-driven trading outcomes. Net imports are generally an equilibrium outcome of market clearing: cross-border exchanges respond to prices, flexibility, and availability across Europe, and not only to Switzerland's physical adequacy needs. As a result, Switzerland may import substantially more electricity than it would strictly need to meet demand, even if domestic resources would in principle be sufficient, simply because importing can be economically attractive.

As previously mentioned, for security of supply purposes, we argue that winter net imports should be complemented by a measure of winter import exposure, defined as the minimum volume of electricity Switzerland would need to import over the winter period to fully meet its electricity demand. This framing captures a structural winter gap: it measures the system's reliance on imports rather than the balance of cross-border flows. The difference matters because realized net imports may be high even when exposure is low. A simple example illustrates this point. If a neighboringring country such as Germany deploys large amounts of wind power, periods of high wind output can depress wholesale prices. In those hours, Switzerland may react to market signals and import significant amounts of electricity because it is economically attractive to do so, even if domestic resources could cover demand. For this reason, structural exposure should complement net imports as an indicator, as the latter primarily reflect the outcome of market clearing.

Combining the two measures also helps interpret the winter gap in more detail. High structural exposure combined with high net winter imports corresponds to the classic case of significant import dependence: both an adequacy-based view and realized trade outcomes point to a substantial reliance on foreign supply, suggesting that domestic availability and capacity are insufficient to cover demand without considerable imports. On the other end, low structural exposure and low net imports is the other clear-cut situation, indicating limited reliance on imports both in structural terms and in seasonal trade outcomes. Low exposure but high net imports, by contrast, is the case in which net imports are most likely to be misleading as a security of supply indicator: imports might be high mainly because market conditions make them economically attractive, reflecting arbitrage opportunities rather than a lack of domestic supply and/or capacity.

This distinction has important implications for how we assess the winter gap and for how we understand Switzerland's security of supply in an integrated European system. In particular, it shifts the focus from simply reducing average net winter imports, which may largely reflect prices and efficient electricity trading, towards reducing winter import exposure. In this study, we therefore assess both structural winter import exposure and net winter imports, enabling a more granular analysis of Switzerland's winter gap and a clearer separation between adequacy requirements and market-driven dispatch under the assumed scenarios.

We start by addressing the central question of this project: whether the six scenarios proposed by Axpo contain sufficient domestic capacity to reduce Switzerland's winter import exposure (interpreted here as winter import dependence) to 5 TWh or less. The winter gap is therefore treated not as a market outcome, but as an indicator of domestic adequacy: the extent to which the Swiss system can cover winter demand with domestic resources while limiting imports.

To address this question, we rely on a synthetic set of simulations under quasi-autarky conditions, in which Switzerland is modeled as a system with no export capability and with the possibility of importing electricity from neighboringring countries at a very expensive cost. In other words, import is modeled as the last available option before load shedding. The purpose of this exercise is not to reproduce actual market outcomes, but to isolate the internal adequacy of each scenario and to quantify how the domestic system behaves when cross-border exchanges cannot be used as a buffer but primarily as a last option.

Under this assumption, net electricity imports can be directly interpreted as a measure of the Swiss structural winter import exposure. If a scenario produces winter imports below 5 TWh under these quasi-autarky conditions, it provides evidence that the domestic system contains enough capacity and sufficiently usable energy to limit winter import exposure to the targeted level [4].

The results in terms of seasonal and monthly net imports for the six scenarios under quasi-autarky conditions are summarized in Figures 4.3.1 and 4.3.2, respectively. All the six scenarios remain below the 5 TWh winter exposure threshold, indicating that the scenario portfolios contain sufficient resources to limit the winter import exposure to the target level. Moreover, the imports are concentrated in winter and remain limited in magnitude, consistent with the interpretation that the residual dependence is predominantly seasonal rather than systemic. These findings are consistent with, and further support, the preliminary assessment of winter usable energy presented in Section 3.1.

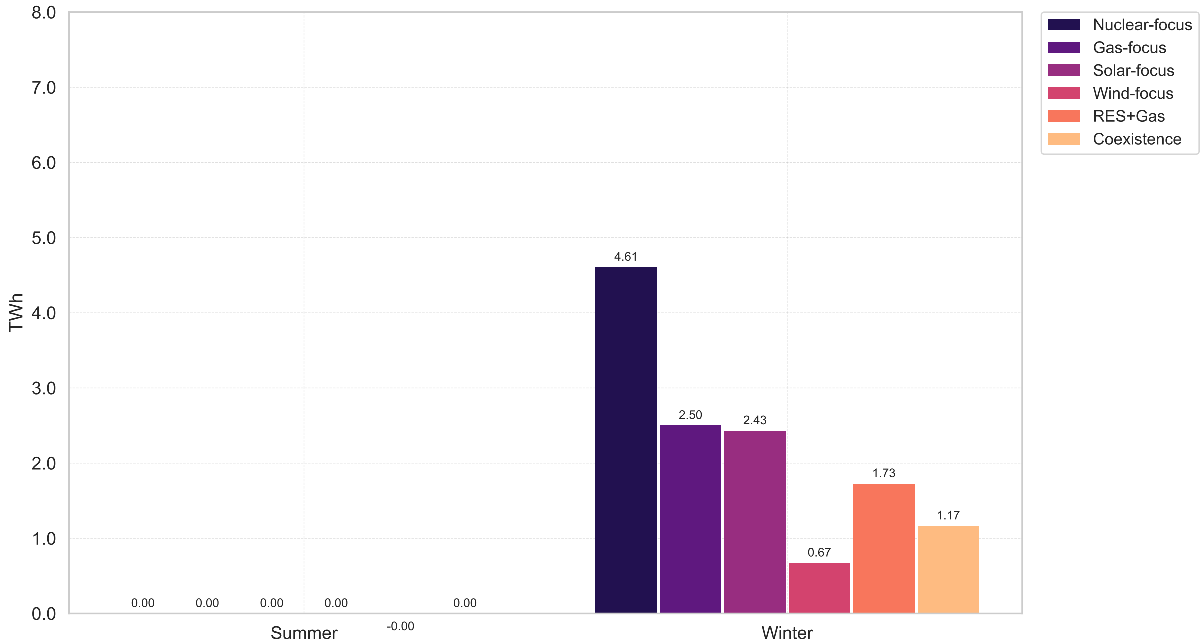



Figure 4.3.1: Seasonal net imports of electricity in Switzerland in the quasi-autarky scenarios.

Figure 4.3.3 illustrates how energy is dispatched under the quasi-autarky conditions (RES+Gas scenario displayed for illustrative purposes), highlighting the respective contributions of energy injections (generation, storage discharging, import, curtailed energy; showed as positive values) and withdrawals (demand, storage charging, electrolysis, export; showed as negative values) within the Swiss system. These dispatch patterns are central to understanding how the various scenarios maintain a winter import exposure below the target level, and they are examined in more detail in

[4]Conditional to the assumptions of study (on weather years, demand, capacities, usable energy, and capacity factors) and the simplifications (spatial aggregation, perfect foresight, linearized market model).

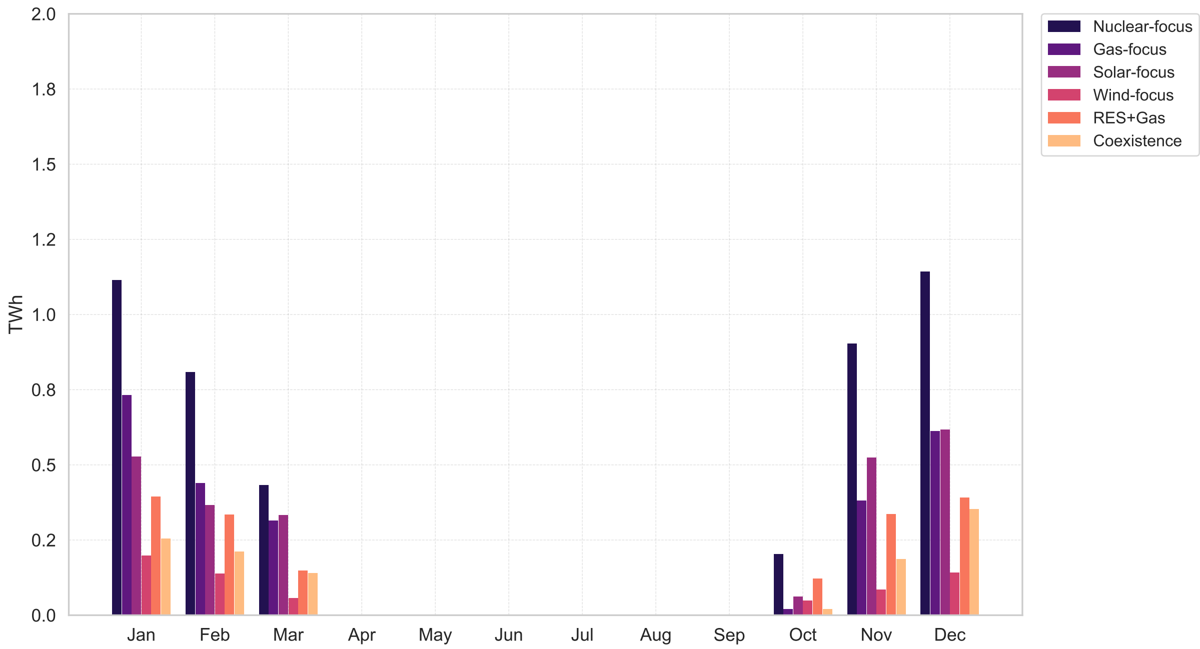



Figure 4.3.2: Monthly net imports of electricity in Switzerland in the quasi-autarky scenarios.

the following subsections with a focus on:

- the seasonal and short-term role of hydropower;
- the contribution of solar and wind in winter;
- the operations of dispatchable capacity, which ultimately determines whether residual load can be met during prolonged low-renewable periods.

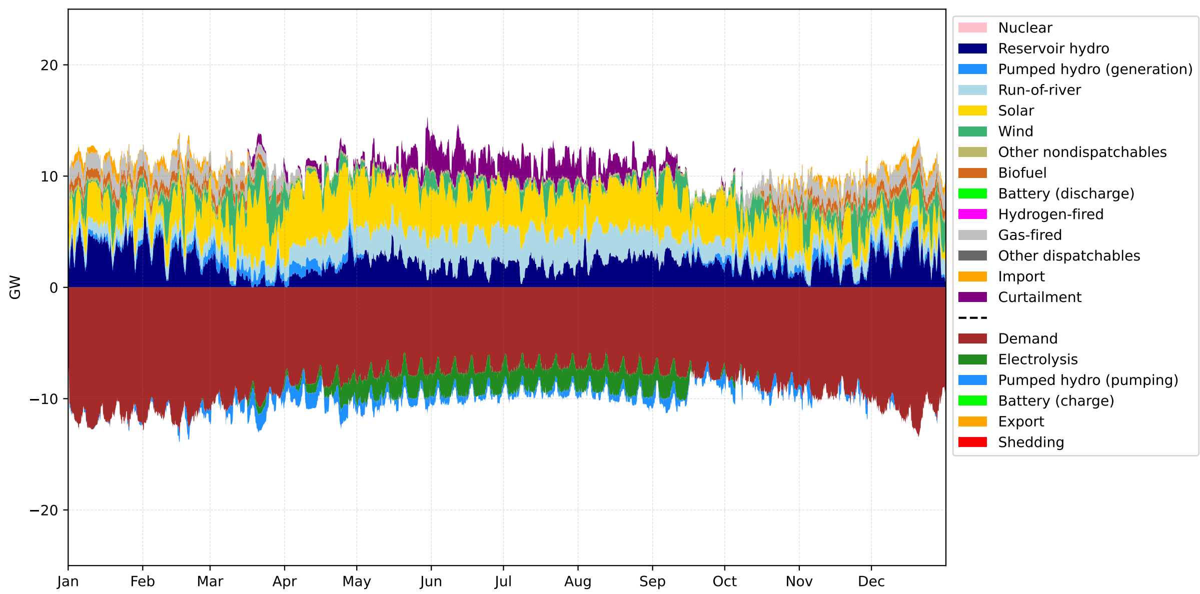



Figure 4.3.3: Annual energy dispatch (daily average) in Switzerland under the quasi-autarky scenario. The RES+Gas scenario is shown for illustrative purposes.

*Overall, the six Axpo scenarios appear to contain sufficient capacity to achieve a structural winter import exposure below 5 TWh. Importantly, this conclusion should be read as a preliminary ad-*

*equacy benchmark rather than a statement about the most likely real-world import volumes: the quasi-autarky simulations deliberately treat cross-border imports as a last option to allow the analysis of the domestic ability to cover winter demand in isolation.*

To complement the analysis on the winter gap, we assess net winter imports in Switzerland under market-integrated conditions, i.e. using the same economic dispatch framework but with Switzerland fully connected to the European countries represented in the model.

The resulting dispatch patterns are shown in Figure 4.3.4 (RES+Gas scenario for illustrative purpose). In addition, Figure 4.3.5 reports the seasonal net imports for the six scenarios considered. It can be clearly observed that net winter imports exceed 5 TWh in all scenarios, even when the simulations under quasi-autarky conditions indicate that domestic capacity is, in principle, sufficient to keep winter import exposure below the 5 TWh target. This divergence is a direct signal of market-driven dispatch. Whenever cheaper electricity is available in neighboringring countries, Switzerland imports it and avoids dispatching more expensive domestic generation, even if that generation exists and could cover the winter demand (at least partially).

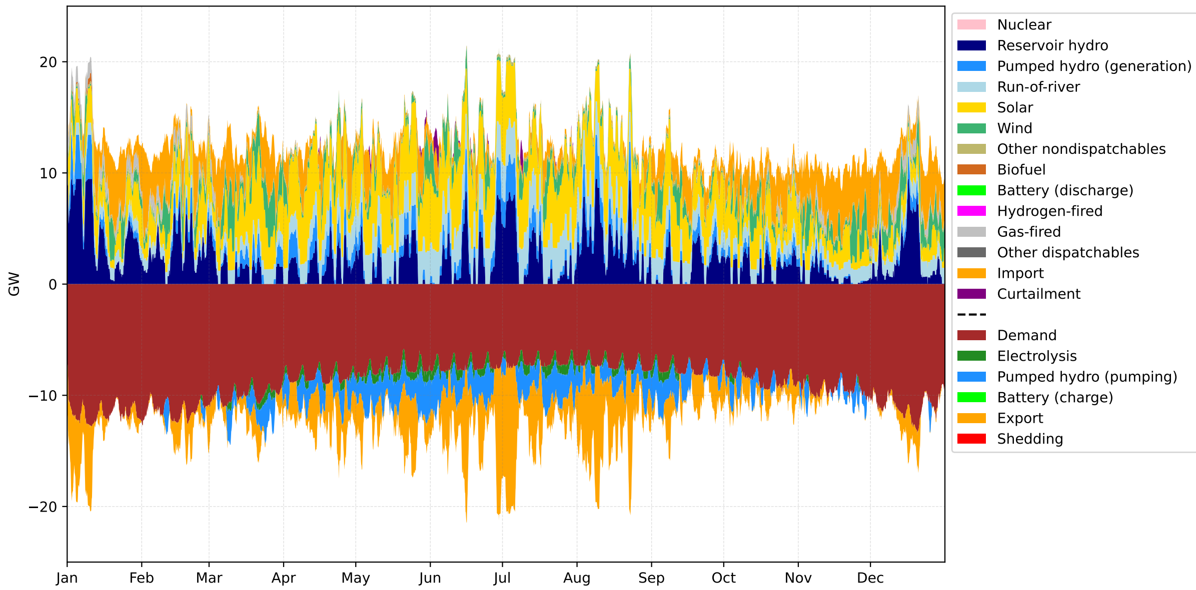



Figure 4.3.4: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario. The RES+Gas scenario is shown for illustrative purposes.

The magnitude of net imports differs across scenarios, as shown in Figure 4.3.5. The Gas-focus scenario shows the largest winter imports, reaching approximately 14.5 TWh, followed by the Wind-focus scenario at around 9.8 TWh. The remaining scenarios present values ranging from 7.1 TWh to 8.8 TWh.

These differences are best understood as *a portfolio–market interaction*. Scenarios with higher marginal-cost domestic generation rely more on imports when neighboringring countries present enough low-cost energy. Conversely, portfolios with more abundant low-cost generation tend to exhibit lower net imports because they are competitive in a larger share of winter hours. This pattern is also evident in summer, where all scenarios maintain a net exporting position (negative values) except for the Gas-focus scenario. This outcome reflects the comparatively high average marginal generation cost of the Gas-focus scenario, which makes imports economically preferable even during periods of typically high domestic availability. Consequently, the variation in net imports across scenarios demonstrates that Switzerland responds efficiently to market price signals, import-

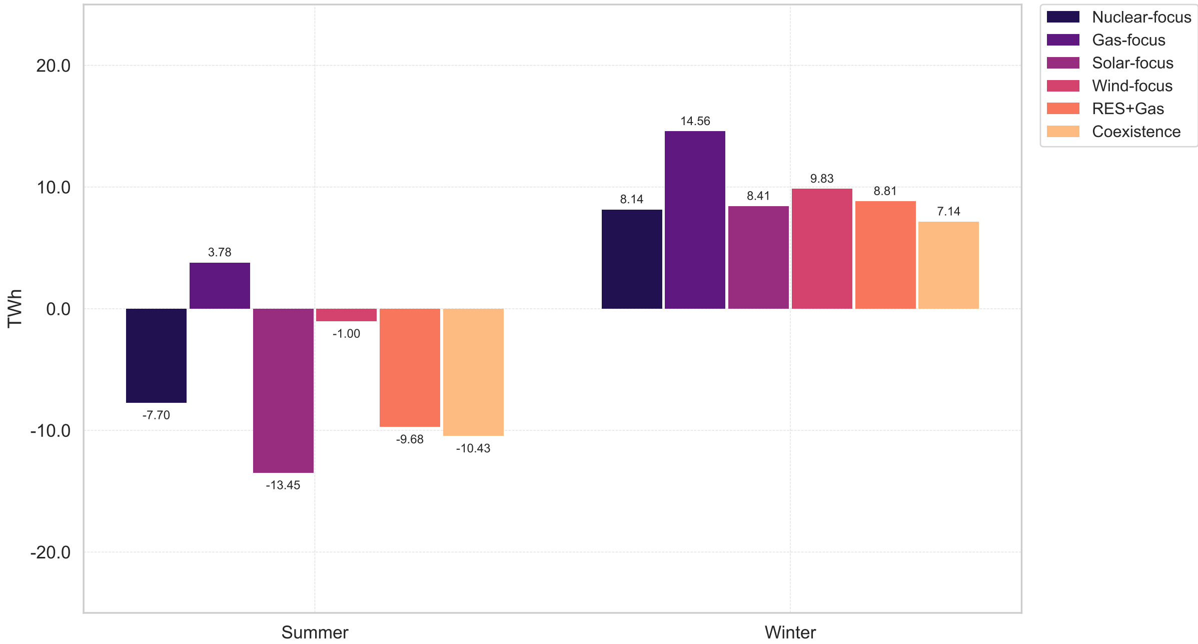



Figure 4.3.5: Seasonal net import of electricity in Switzerland under the market-integrated scenarios.

ing when external electricity is cheaper, and shifting toward domestic resources (or even exporting) when they are more competitive.

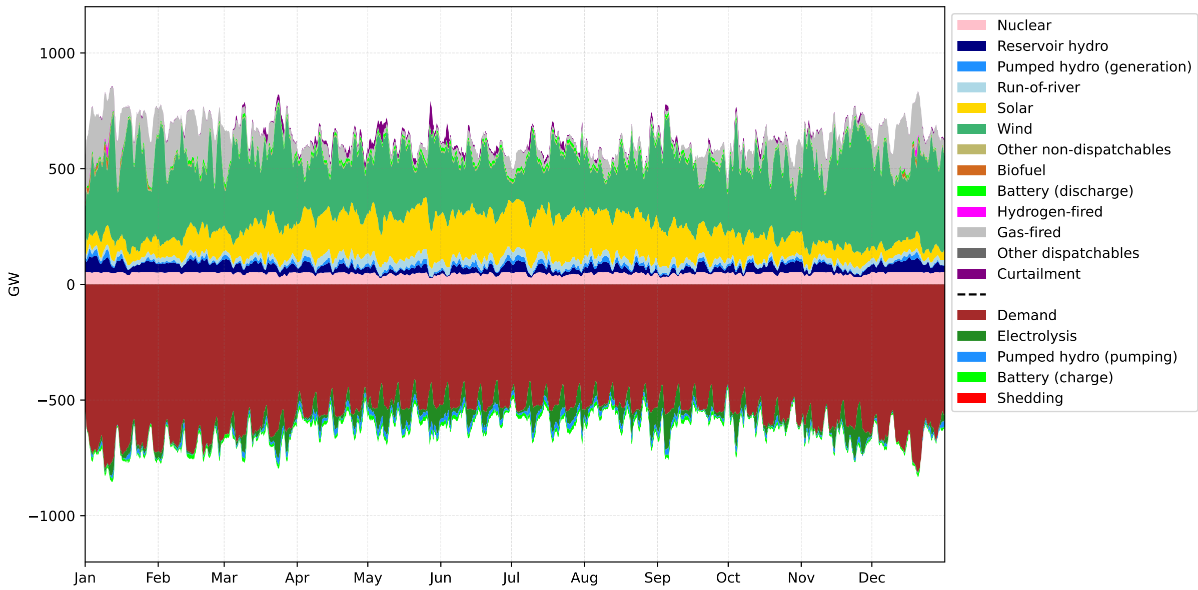



Figure 4.3.6: Annual energy dispatch (daily average) in Europe under the market-integrated scenario. The RES+Gas scenario is shown for illustrative purposes.

This market-driven pattern is clearly visible when comparing Swiss and European dispatch (Figures 4.3.4 and 4.3.6). For example, strong wind generation in Europe in late November and beginning of December leads to abundant low-cost energy (see Figure 4.3.6), making imports into Switzerland economically attractive and therefore more pronounced, as shown in Figure 4.3.4. By contrast, when European wind availability is low, such as in the beginning of July, Switzerland shifts towards exporting. Those exports are typically enabled by reservoir hydropower dispatch (see Figure 4.3.4), which can concentrate generation in high-price hours and sustain competitive arbitrage (the hydropower dispatch pattern is discussed in detail in the next sections).

Switzerland is particularly well positioned to capture these opportunities because of (i) its geographic location at the intersection of large European countries complemented with significant cross-border interconnections and (ii) the operational flexibility provided by its hydro fleet, which supports can support arbitrage across hours and enhances the value of importing low-cost electricity when available and exporting during moments of widespread energy scarcity. These results highlight an important insight of this study: elevated net winter imports should not automatically be interpreted as a security of supply problem.

In addition, these results indicate that imports are an equilibrium outcome shaped by European conditions, and therefore need to be interpreted alongside the structural exposure metric introduced above.

*Across scenarios, the quasi-autarky simulations suggest winter import exposure remains below 5 TWh. In contrast, the market-integrated simulations produce winter net imports above 5 TWh in all scenarios. This distinction has an important implication: if additional capacity expansion is deemed necessary to strengthen security of supply and maintain winter import exposure below the target threshold, it should explicitly account for market dynamics, market integration, and the evolving generation mix in neighboringring European countries.*

Adequacy-driven investments that ignore these interactions risk being economically inefficient: the system may end up procuring high-cost capacity that is rarely dispatched, because imports could continue to play an important role. In practice, this argues for prioritizing a portfolio of solutions that can support energy supply in winter and is also cost-effective under market-driven dispatch.

## 4.4 The role of reservoir hydro for seasonal flexibility

An essential complement for assessing the winter gap is the temporal dimension of supply, as not all technologies can contribute to winter supply in the same way. Dispatchable generation can be scheduled flexibly (within the limits of fuel availability and operational constraints), while variable renewable energy (e.g. solar, wind, run-of-river) is largely non-dispatchable and must be absorbed by the system when it is produced. Reservoir hydro sits in between these categories and is particularly valuable because it can provide a seasonal buffer. In fact, while most water inflows occur during spring and summer, storage dams allow this energy to be shifted and delivered during winter, when demand is higher and domestic generation is often more limited.

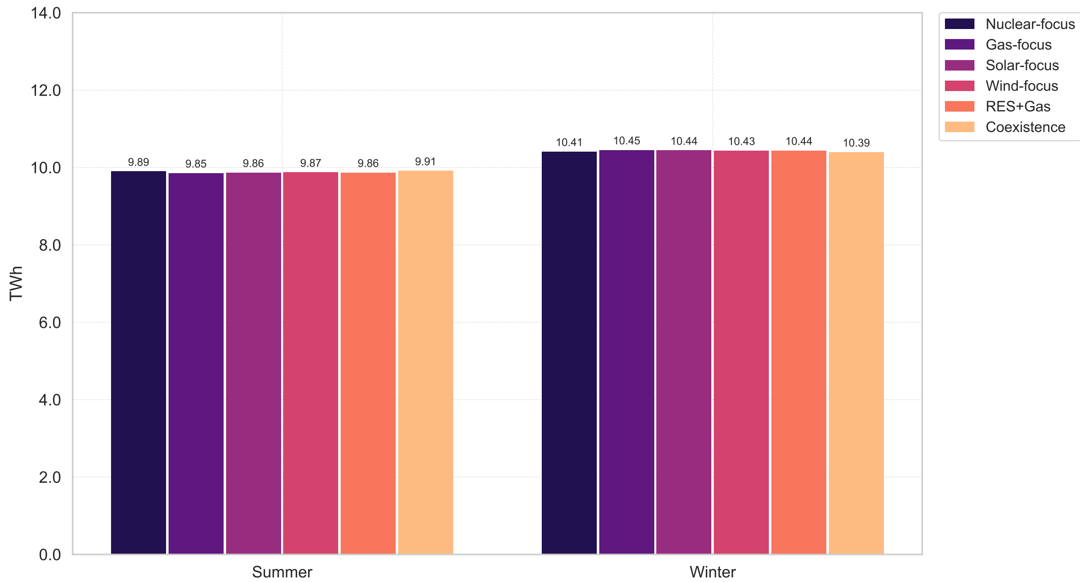



Figure 4.4.1: Seasonal production of reservoir hydropower plants in Switzerland under the quasi-autarky scenarios.

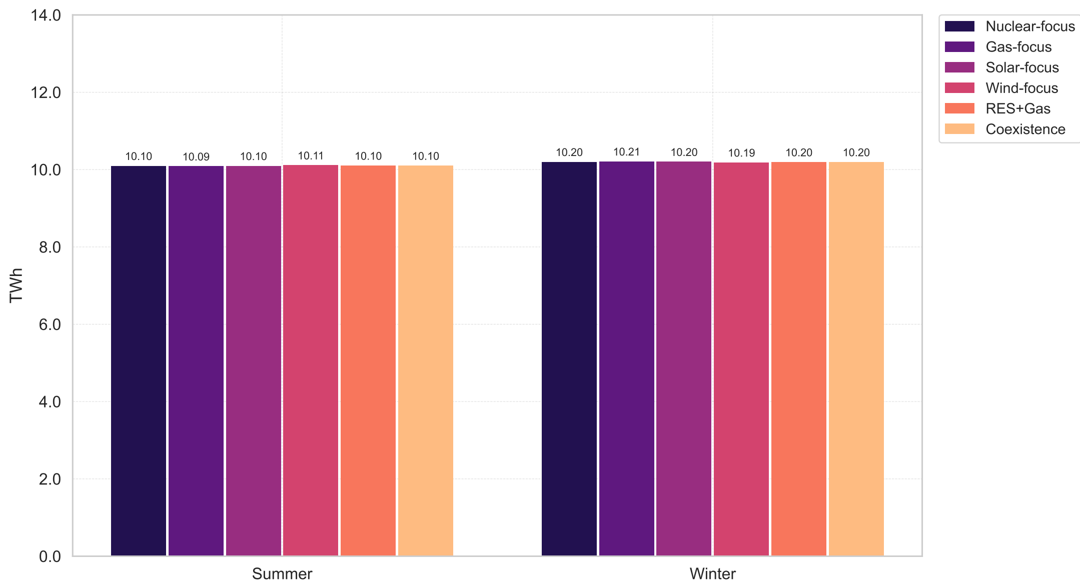



Figure 4.4.2: Seasonal production of reservoir hydropower plants in Switzerland under the market-integrated scenarios.

The magnitude and the dynamics of this seasonal energy shift is a key determinant of winter energy security in Switzerland. Historical observations show that annual and seasonal reservoir production can vary due to hydrological conditions and reservoir management strategies. However, they also show a consistent trend in seasonal shift. In this section, we focus on the mechanics of the seasonal shift in our simulations, and on what it implies for the interpretation of the winter gap.

We start by evaluating the role of reservoir hydro as a seasonal buffer in the quasi-autarky scenarios. Figure 4.4.1 shows the cumulative seasonal production of reservoir hydro across the six scenarios. The values are similar, and winter reservoir production is approximately 10.4 TWh across all the six scenarios. This winter output can be decomposed into roughly 3.3 TWh of winter inflow and 7.1 TWh of seasonal shift, i.e. energy stored in summer and discharged during winter. This seasonal shift corresponds to approximately the maximum seasonal shift allowed by the modeling assumptions.[5] This result can be easily understood: under the quasi-autarky assumption, where the system can rely on imports just as a last option, the model is naturally pushed to conserve summer inflow and discharge it during the winter period when the energy supply is more scarce.

Figure 4.4.2 reports the corresponding results under market integration, where Switzerland is fully connected to the neighboringring countries and electricity can be freely imported and exported. At seasonal level, the qualitative insight remains similar: even though the winter generation is slightly lower than the previous case (around 10.2 TWh across all scenarios), reservoirs still tend to enter the winter period with a high state of charge.

*Two points are of particular relevance. First, in both the quasi-autarky and the market-integrated scenarios we can observe a significant seasonal shift, suggesting that shifting water from summer to winter presents value both in terms of security of supply and market-driven outcomes. This behaviour is in line with what can be observed historically: reservoirs are typically close to full at the beginning of winter, implying that a large part of the seasonal shift is already maximized (or close to maximized) under the current market structure. This suggests that reservoir hydropower's contribution to winter security is, to a significant extent, structural: it reflects the combination of Switzerland's hydrology and storage infrastructure, and the fact that winter electricity tends to be more valuable than summer electricity. In other words, the seasonal shift is naturally market-driven and economically rational, and not only the result of explicit winter adequacy policies.*

To prove this last point, in Figures 4.4.3 and 4.4.4, the reservoir storage filling levels from the two simulation settings (quasi-autarky and market-integrated) are compared with historical data. In both cases, the simulated patterns closely resemble the historical evolution: storage levels increase throughout summer and decrease during winter as the water is used for generation. This suggests that the model is able to capture the core seasonal dynamics of the system.

However, it should be noted that the modeling and scenario assumptions allow for a somewhat overly optimal utilization of reservoir hydro. In particular, the aggregation of all reservoir hydropower plants into a single representative unit neglects cascade topology, inflow diversification, network constraints, and other technical and operational frictions. Moreover, the perfect foresight assumption allows the reservoir hydro to be dispatched while having a complete knowledge on periods of energy scarcity and abundance over the simulated year. These simplifications and assumptions tend to smooth constraints and enhance flexibility, leading to results that are more optimal than would be achievable in reality. For instance, the high reservoir filling levels at the end of November and beginning of December, observed in both simulation settings, are driven by abundant wind production

[5] Total aggregated reservoir storage is approximately 8.38 TWh. To reflect the effects of spatial aggregation and operational constraints, we impose a lower bound of 10% and an upper bound of 95% on the state of charge. This implies that at most 85% of storage capacity, or about 7.1 TWh, can be used for seasonal shifting.

in Europe which leads to significant imports and low hydro production in Switzerland. This can be considered as a byproduct of the perfect foresight assumption.

Nevertheless, the qualitative pattern remains consistent with observed historical data. Notably, historical reservoir levels are on average around 85% at the end of September, which is well aligned with the simulated seasonal patterns. This reinforces the conclusion that the model captures the fundamental economic and hydrological dispatch logic underlying Switzerland's seasonal reservoir storage behaviour.

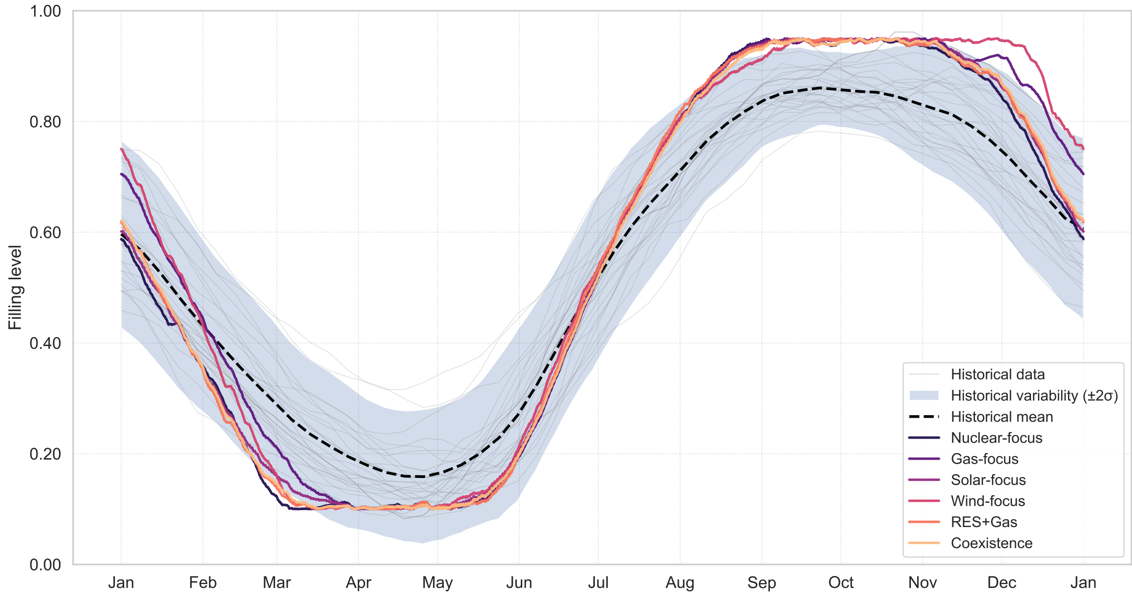



Figure 4.4.3: Reservoir storage filling levels under the quasi-autarky scenarios. Historical data are adapted from the ones available in [10].

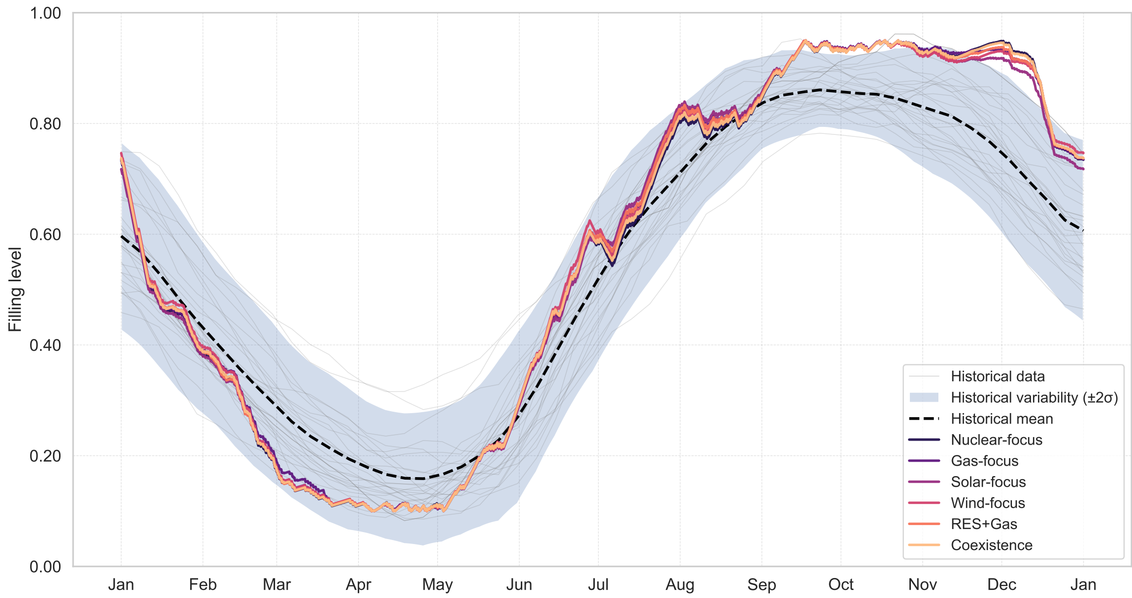



Figure 4.4.4: Reservoir storage filling levels under the market-integrated scenarios. Historical data are adapted from the ones available in [10].

This observation has two implications for the broader analysis of this project. On the one hand, reservoir hydropower is a fundamental pillar for winter adequacy and can substantially reduce structural exposure. On the other hand, as the seasonal shift in the simulations is already near its operational limit in many cases (as it is often today), additional winter supply is unlikely to come from "enhanced shifting" from reservoir plants, unless storage capacity upgrades are performed[6]. Moreover, one should also note that the amount of seasonal shift largely depends on the magnitude and the temporal profile of the hydro inflow. Both these aspects can vary significantly across years, and this uncertainty should be evaluated more comprehensively.

[6] One should also note the total storage capacity (reservoir and pumped hydro plants together) used in this study is equal to 9.88 TWh and is higher than the one present today (around 8.89 TWh [10]). However, as mentioned before, in this study we decouple reservoir and pumped hydro storage (see Table 3.1.2). The reservoir hydro fleet analyzed in this section accounts for approximately 8.38 TWh.

## 4.5 The role of reservoir hydro for short-term flexibility

Beyond acting as a seasonal energy buffer, Swiss reservoir hydropower can also provide short-term operational flexibility. By continuously adjusting generation in response to market signals, reservoir plants can rapidly ramp up or down, thereby shaping Switzerland's cross-border import–export patterns. This flexibility can be observed on intra-seasonal timescales (e.g. monthly) and is complementary to the seasonal shifting role discussed in the previous section. In fact, seasonal storage determines how much energy can be reallocated across the year, while short-term flexibility determines when that energy is released (or withheld) within and across shorter temporal horizons.

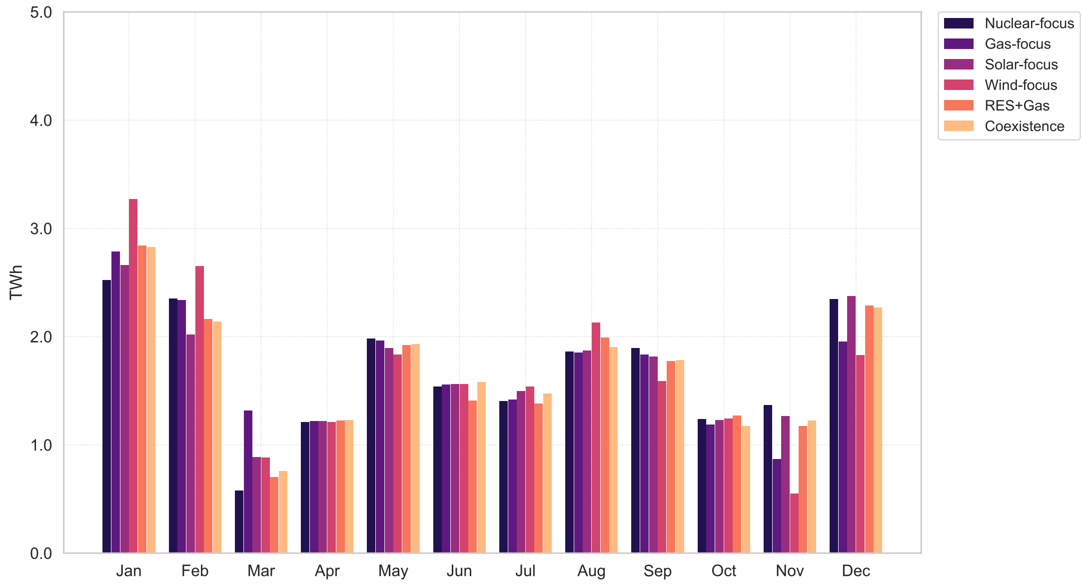



Figure 4.5.1: Monthly production of reservoir hydropower plants in Switzerland under the quasi-autarky scenarios.

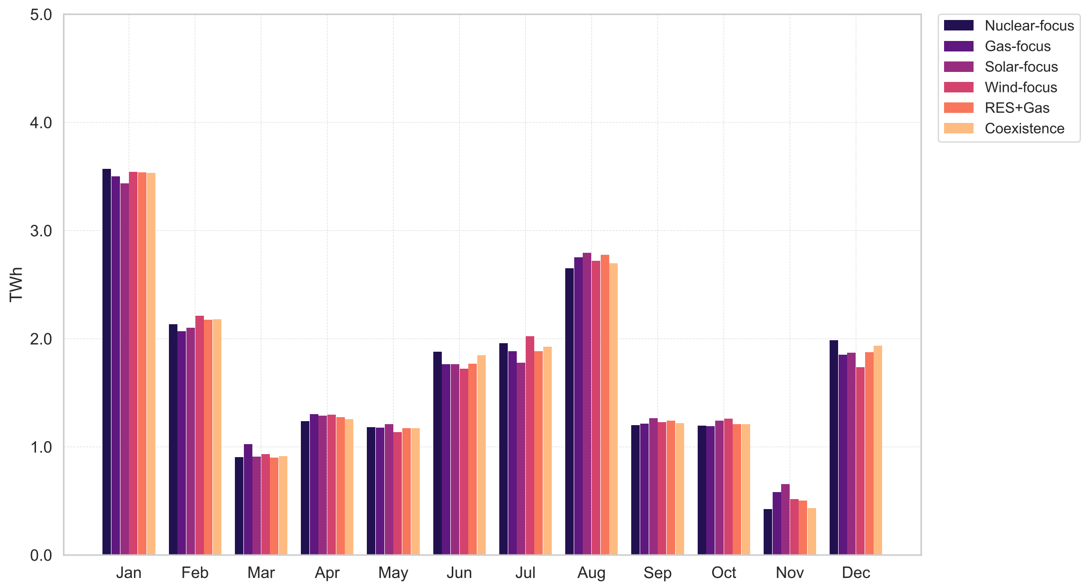



Figure 4.5.2: Monthly production of reservoir hydropower plants in Switzerland under the market-integrated scenarios.

Figures 4.5.1 and 4.5.2 show monthly reservoir hydro production under the quasi-autarky and market-integrated scenarios, respectively. Under quasi-autarky conditions, monthly production exhibits clear scenario-dependent variability. Even if the seasonal generation remains comparable across scenarios (as previously discussed, see Figure 4.4.1), the monthly reservoir generation responds to domestic balancing requirements, specifically the Swiss electricity demand, the availability of domestic non-hydro generation, and residual operational constraints within the Swiss system. Consequently, the model produces monthly dispatch profiles that differ across scenarios, especially in winter.

For example, in November, the Gas-focus and Wind-focus scenarios show reservoir hydro production below 1 TWh, while the other scenarios remain well above that level. A similar pattern appears again in December. Conversely, in January and February, the Wind-focus scenario presents higher reservoir production than the other scenarios, while the Gas-focus scenario has the highest reservoir production in March. These shifts indicate that, in a setting with limited market interaction, reservoirs are operated as an internal flexibility resource: they compensate for scenario-specific scarcity and surplus periods in domestic supply, leading to different monthly dispatch patterns across scenarios.

Under market integration, as shown in Figure 4.5.2, monthly reservoir production becomes more aligned across scenarios, with reduced dispersion in both timing and magnitude. This convergence suggests that short-term reservoir dispatch is no longer driven primarily by Swiss domestic conditions, but more by the wider European system. In other words, reservoir hydro shifts from being mainly an instrument of domestic balancing to functioning as a flexibility interface between Switzerland and other European countries. In fact, Swiss reservoir hydro can adapt its output to external residual demands and cross-border price differentials, supporting cost-effective imports and exports during periods of abundant or scarce low-cost energy in neighboringring countries.

The link between reservoir hydro dispatch and cross-border flows is apparent when hydro production is assessed jointly with imports and exports in the market-integrated scenarios. As previously shown in Figures 4.3.4 and 4.3.6, Swiss reservoir hydro production is highly correlated with net import and export positions. For example, at the beginning of July, a pronounced increase in reservoir hydro generation coincides with a spike in exports (see Figure 4.3.4). At the European level, this period corresponds to a period of low wind generation (see Figure 4.3.6), which leads to tight system conditions. Consequently, Swiss reservoirs can respond by producing electricity and exporting it, contributing to system balancing under constrained conditions.

Conversely, in November, reservoir hydro generation is low while imports are considerably high. This pattern aligns with periods of strong wind generation in Europe, when electricity is abundant and electricity prices are likely comparatively low. In such conditions, it is economically optimal for Switzerland to conserve stored water and rely on imports. Overall, reservoir hydropower functions as both a temporal and spatial arbitrage mechanism: it reduces generation to absorb low-cost imports during periods of European surplus and increases generation to support domestic supply and exports when system conditions tighten.

*These dynamics highlight an important feature of Switzerland's power system: the flexibility of its reservoir hydro fleet enables it to act as a regional balancing asset. By absorbing electricity during times of high low-cost energy generation and supplying electricity during scarcity in Europe, Switzerland improves the performance of the interconnected system. From a winter adequacy perspective, this short-term flexibility complements seasonal storage by preserving water for periods when it is most valuable, while still exploiting favorable market conditions throughout the year.*

Overall, the results confirm that reservoir hydro contributes to the winter security of supply along multiple temporal dimensions. Seasonal shifting contributes significantly to winter energy security, while short-term operational flexibility allows Switzerland to adapt dynamically to periods of domestic and European energy surplus and scarcity.

## 4.6 The role of pumped hydro for seasonal and short-term flexibility

Pumped hydro storage (PHS) complements reservoir hydro by providing dispatchable output and the possibility of storing energy through pumping. Conceptually, under the assumptions of this study, PHS functions as a pure storage technology rather than a net energy source with natural inflow. While reservoir hydro converts natural inflows into electricity, PHS primarily shifts electricity over time by consuming electricity to pump water to an upper reservoir and generating later by releasing this water through turbines. Because the pump-turbine cycle leads to efficiency losses, PHS is typically a net consumer of energy over a full cycle, but it can deliver highly valuable flexibility and controllable power when needed.

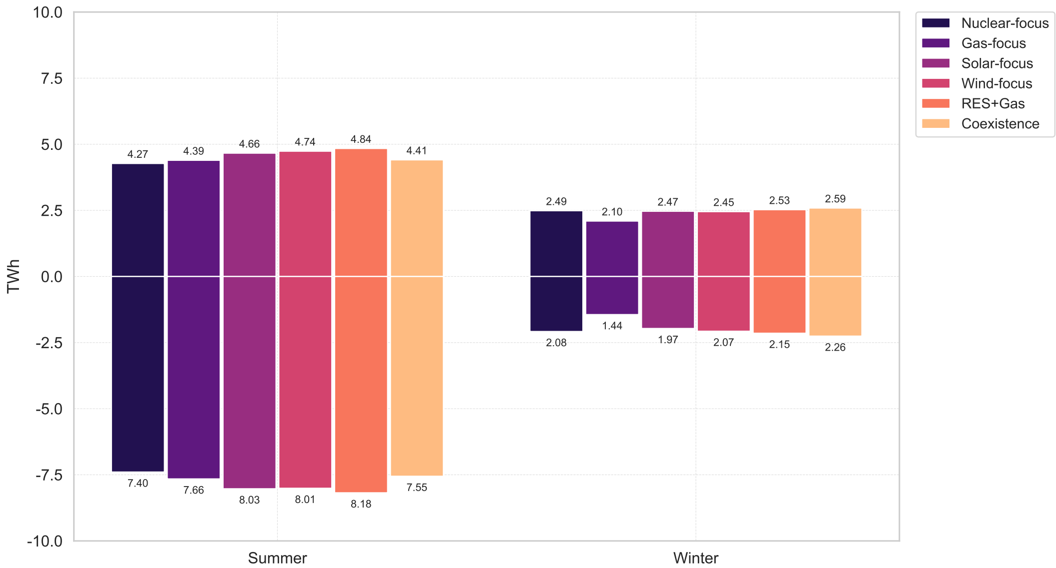



Figure 4.6.1: Seasonal generation (positive values) and pumping (negative values) of PHS plants in Switzerland under the market-integrated scenarios. Generation shows the energy after all efficiency losses, i.e. the net amount of energy injected into the system. Pumping shows the energy before any efficiency losses, i.e. the net amount of energy extracted from the system.

In the simulated settings, PHS contributes along two temporal dimensions. First, it provides short-term flexibility through frequent charge-discharge cycles, absorbing electricity during surplus periods and releasing it when the system requires additional supply. Second, PHS can contribute to longer-duration energy shifting across months, charging during periods with abundant generation (typically summer) and discharging during periods of relative scarcity later in the year. Importantly, these two modes are not mutually exclusive: optimal operation may combine short-term cycling with a tendency to preserve some stored energy for periods of expected scarcity. Figure 4.6.1 shows seasonal pumping and generation across scenarios under the market-integrated assumption. Significant pumping and generation in both summer and winter highlights the short-term flexibility role of PHS. At the same time, total generation in winter exceeds the total pumping energy, suggesting that the model uses PHS to shift energy across longer time spans from summer to winter. However, this pattern should be interpreted cautiously: on the one hand, it highlights the theoretical potential of PHS for long-term storage; on the other hand, one should note that these results reflect optimal dispatch within the assumed modeling framework and do not necessarily represent observed real-world operating practices.

Figure 4.6.2 shows seasonal pumping and generation under the quasi-autarky assumption. Under

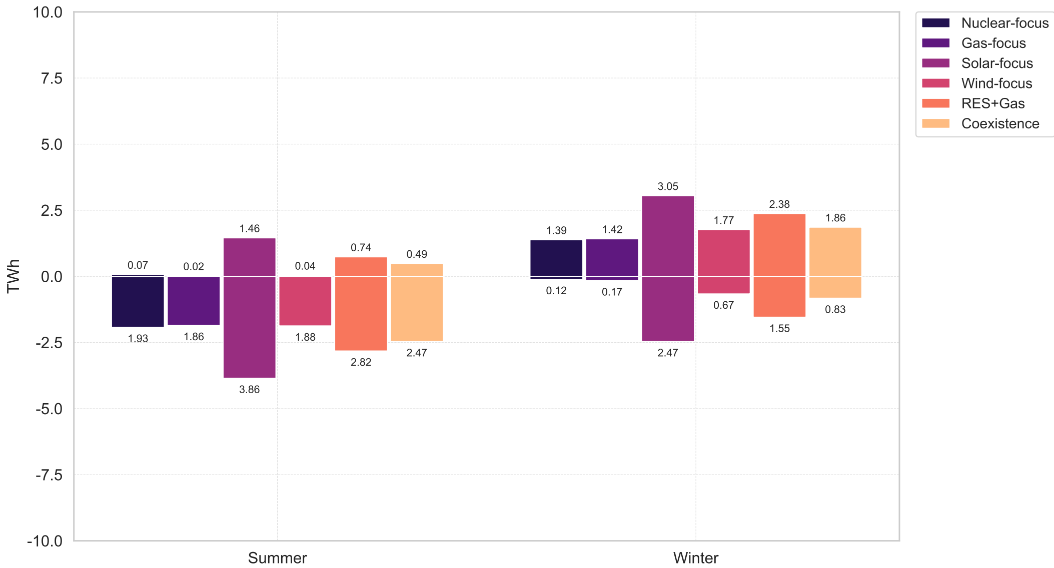



Figure 4.6.2: Seasonal generation (positive values) and pumping (negative values) of PHS plants in Switzerland under the quasi-autarky scenarios. Generation shows the energy after all efficiency losses, i.e. the net amount of energy injected into the system. Pumping shows the energy before any efficiency losses, i.e. the net amount of energy extracted from the system.

these conditions, PHS is used more prominently as a seasonal buffer, with energy stored in summer and released in winter. This effect is particularly pronounced in scenarios with lower renewable capacities, namely the Nuclear-focus and Gas-focus cases, where nearly all pumping occurs in summer and most generation in winter. In scenarios with higher shares of renewables, operation more closely resembles the market-integrated case. For instance, in the Solar-focus scenario, significant pumping and generation occur in both summer and winter, indicating also short-term cycling. However, even in this case, winter generation exceeds winter pumping, implying that part of the energy released in winter originates from storage accumulated during summer.

Overall, the short-term flexibility role is well aligned with observed PHS operations. In practice, PHS plants typically cycle at short-term scales (e.g. daily or weekly), responding to predictable price spreads and balancing needs, and derive value from multiple markets. In this sense, PHS is particularly valuable in renewable-heavy systems because it can absorb surplus generation, thus reducing curtailment, and provide controllable generation when residual demand increases.

By contrast, the interpretation of PHS as a seasonal buffer requires caution. While multi-month storage is physically feasible, in reality many PHS installations are designed and operated primarily for shorter cycles. If a PHS plant can earn substantial value from frequent cycling and ancillary services, dedicating storage volume to long-horizon retention may be economically inefficient. Seasonal PHS operation can nonetheless become attractive under certain conditions: for example, when seasonal scarcity is pronounced, when renewable curtailment in summer months is large, or when dedicated mechanisms explicitly reward long-duration storage or adequacy contributions.

These considerations matter for interpretation of the results in Figures 4.6.1 and 4.6.2. *The short-term dispatch patterns are a solid indicator of PHS's core value as a short-term flexibility provider. The seasonal contribution should instead be read as an indication of technical potential within the considered modeling framework, rather than evidence of a proven real-world operating mode. Overall, PHS can strengthen security of supply by expanding the system's ability to reallocate electricity across time, but its realized contribution depends on storage sizing, operational constraints, and specific market structure.*

## 4.7 The role of other sources of flexibility

While Switzerland's reservoir hydro and PHS plants already provide substantial operational flexibility, this flexibility can be complemented by additional resources such as flexible loads, i.e. demand-side response (DSR), and battery storage systems. These options are often valuable in practice for peak shaving, local congestion management, and mitigating short-lived scarcity events. In the market-integrated simulations, they do not appear to affect significantly the observed outcomes on a seasonal energy basis. In the quasi-autarky setting, they lead to a more relevant impact on the observed net imports, although they do not seem necessary to meet the target level of 5 TWh.

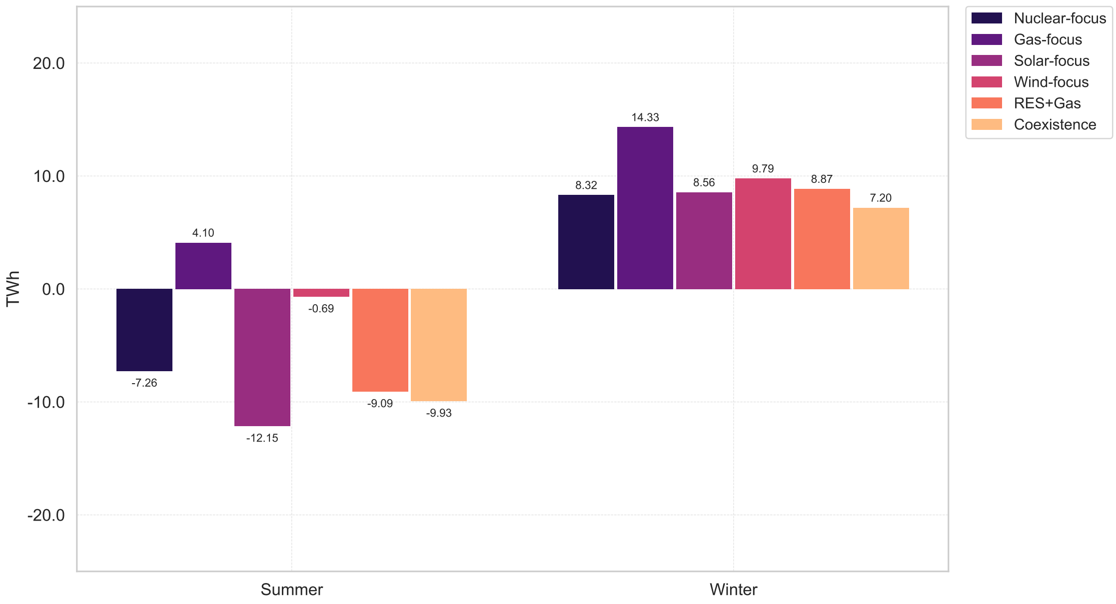



Figure 4.7.1: Seasonal net imports of electricity in Switzerland under the market-integrated scenarios with no flexible demand in Switzerland.

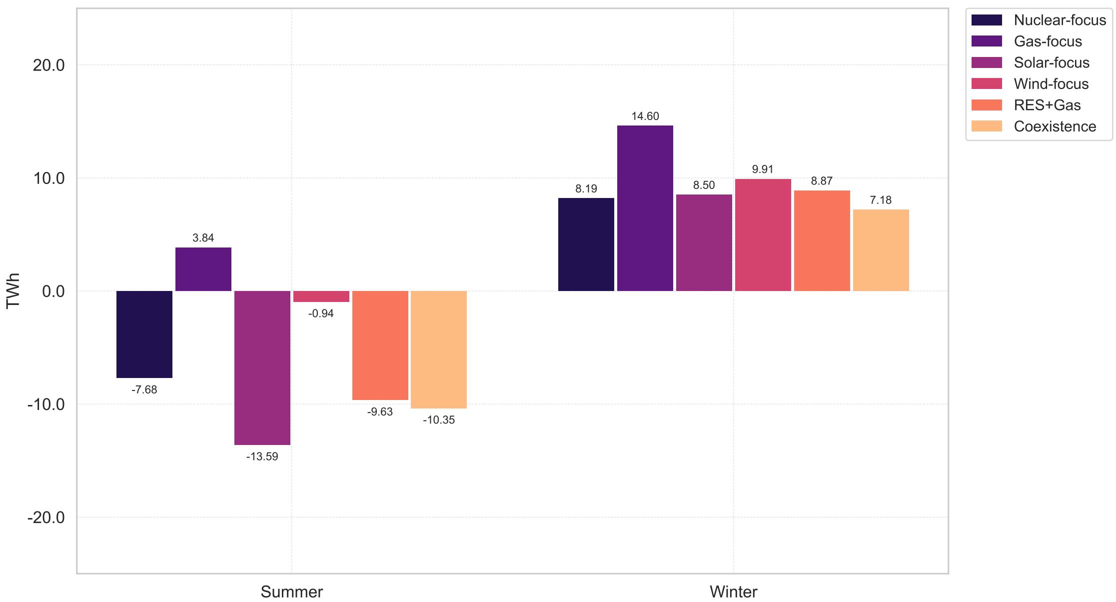



Figure 4.7.2: Seasonal net imports of electricity in Switzerland under the market-integrated scenarios with 2 GW (6 GWh) of batteries in Switzerland.

Figure 4.7.1 shows seasonal net imports for Switzerland under the market-integrated scenarios where Swiss heating and electromobility demand are considered fully inflexible[7]. The results are compared against the market-integrated reference case in Figure 4.3.5. In winter, seasonal net imports change only marginally, indicating that the overall winter energy balance remains largely unaffected by the unavailability of DSR. Summer outcomes are also broadly similar. The main difference is a reduction in net summer exports (or increase in net summer imports) in some scenarios. For example, in the Solar-focus scenario, net exports decrease by approximately 1.3 TWh (from 13.45 to 12.15 TWh) when DSR is not available. Smaller impacts occur in other scenarios as well. This pattern is consistent with the idea that flexible demand can be shifted towards hours with abundant domestic or foreign generation to allow for more exports during economically attractive hours. However, within the modeling assumptions applied here, DSR does not emerge as a major driver of seasonal net import/export volumes under market-integrated setting.

A similar conclusion can be derived for battery storage systems. Figure 4.7.2 shows seasonal net imports when 2 GW of batteries (6 GWh energy capacity) are added to the Swiss system. Seasonal net imports remain close to the original market-integrated results (Figure 4.3.5), suggesting that the additional battery capacity has only a limited impact on energy exchanges at the seasonal scale if Switzerland is well integrated within the broader European system.

Under quasi-autarky settings, additional sources of flexibility play a more pronounced role, although they are not required to meet the 5 TWh import target. Figures 4.7.3 and 4.7.4 present seasonal net imports for scenarios without flexible demand and with 2 GW (6 GWh) of batteries, respectively, and can be compared to the baseline quasi-autarky case in Figure 4.3.1.

In the absence of flexible demand (Figure 4.7.3), winter net imports increase substantially across all scenarios, particularly in those with high shares of renewables. For example, in the Solar-focus scenario, winter imports rise from 2.43 TWh to 4.80 TWh. However, the 5 TWh threshold is not exceeded in any scenario. This reflects the role of flexible demand in reducing temporal mismatches between supply and demand. Without it, these mismatches must be absorbed through storage, incurring in efficiency losses, or through curtailment, leading to higher dependence on imports.

In the second case, with batteries (Figure 4.7.4), the effect is more limited. A noticeable reduction in winter net imports is observed only in the Solar-focus scenario (from 2.43 to 2.11 TWh), while impacts in other scenarios are more limited or negligible. Even if under the simulated conditions their role is not fundamental, batteries help mitigate temporal mismatches between supply and demand and can support pumped hydro storage with lower round-trip losses[8].

*Overall, Switzerland appears to possess sufficient flexibility through its hydropower fleet and interconnections with the European system, which itself provides access to additional flexible demand and storage. As a result, additional short-term flexibility from DSR and batteries has limited influence on seasonal energy balances. In market-integrated scenarios, their impact is limited. In quasi-autarky settings, they reduce winter import exposure by mitigating temporal mismatches and supporting storage operation, particularly in renewable-heavy scenarios. However, they are not required to maintain the targeted level of winter security of supply under the simulated conditions.*

It should be noted that several modeling assumptions, most notably spatial aggregation, perfect foresight, and a simplified economic dispatch framework, tend to reduce the estimated value of short-term flexibility. In real-world operation, uncertainty in demand and renewable generation, fore-

[7] Let us recall that, in the standard scenarios, 20% of heating demand and 50% of electromobility demand are considered flexible within a daily window at Swiss and European level.

[8] In this study, round-trip cycle efficiency is assumed to be 71% for PHS and 85% for batteries.

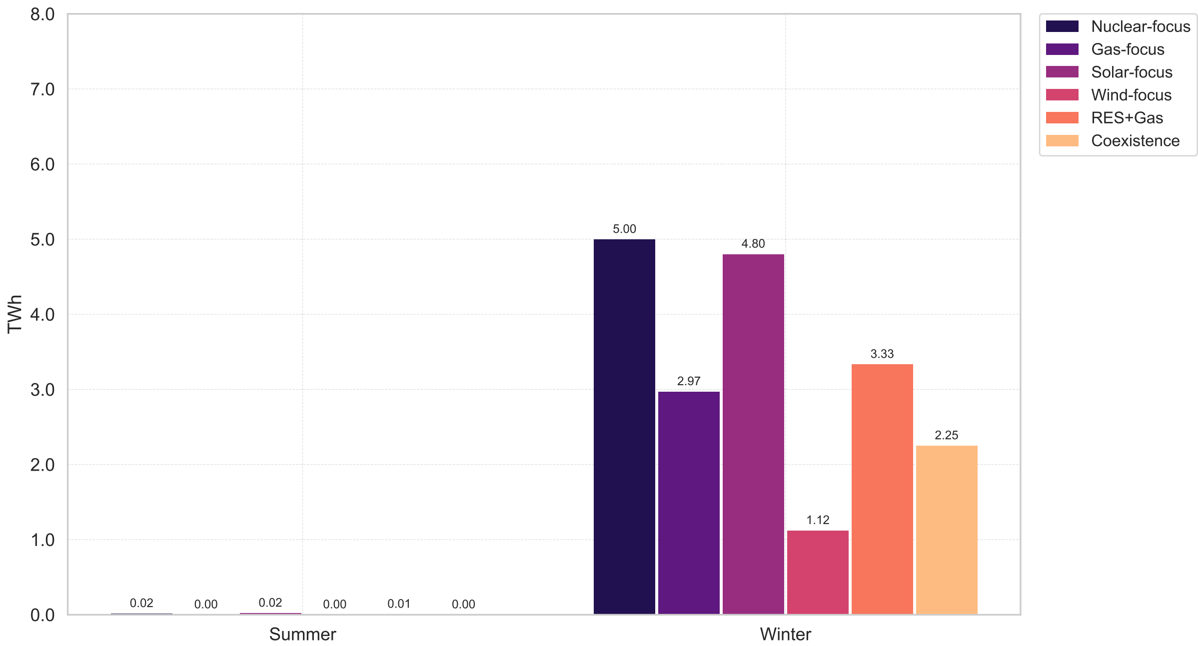



Figure 4.7.3: Seasonal net imports of electricity in Switzerland under the quasi-autarky scenarios with no flexible demand in Switzerland.

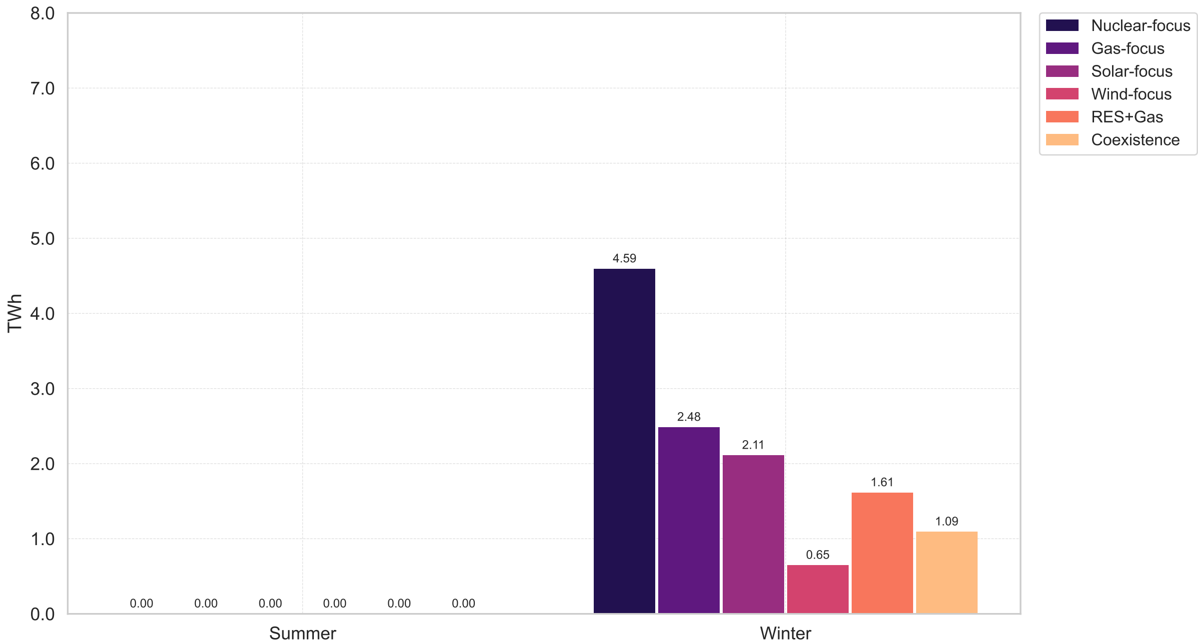



Figure 4.7.4: Seasonal net imports of electricity in Switzerland under the quasi-autarky scenarios with 2 GW (6 GWh) of batteries in Switzerland.

cast errors, unit commitment constraints, and network congestion can increase the importance of fast and distributed flexibility. While DSR and batteries may therefore be of limited relevance for seasonal adequacy, or play a role only when the system is considerably constrained, they may remain important for short-term balancing, congestion management, and overall system robustness, especially in solar-dominated scenarios.

## 4.8 The role of solar and wind

Solar and wind can play distinct but complementary roles in the Swiss power system, mainly because their generation profiles differ over the day and across seasons. These differences can translate into different needs for flexible resources such as reservoir hydro and cross-border interconnections. In a system like the Swiss one, characterized by winter adequacy concerns but valuable short- and long-term flexibility, the temporal structure of renewable generation is often as important as its annual energy volume.

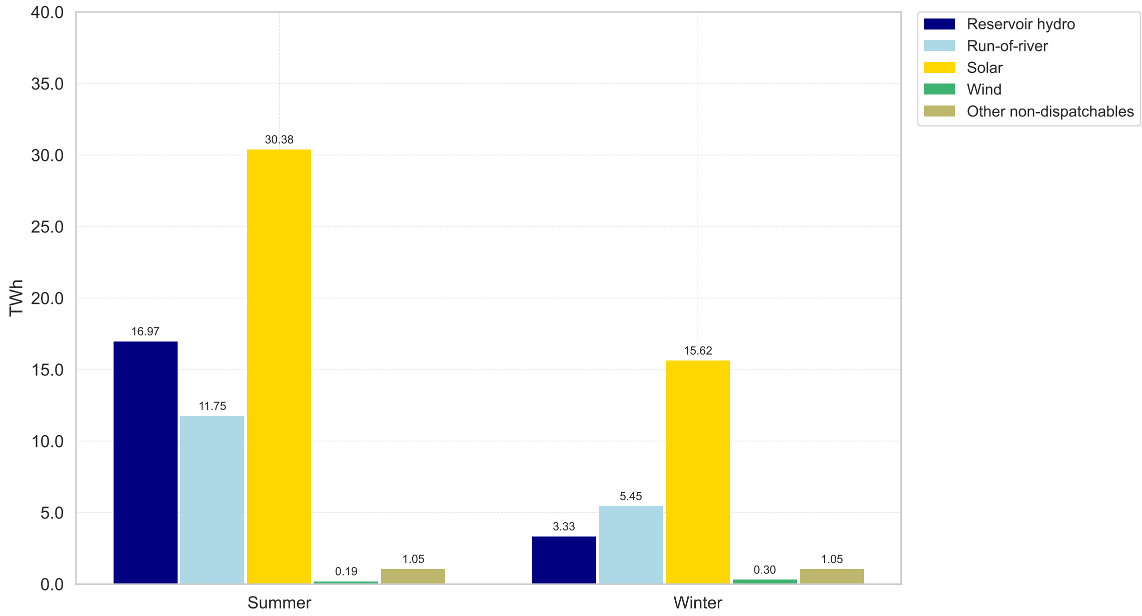



Figure 4.8.1: Seasonal renewable energy supply and hydro inflow in Switzerland in the Solar-focus scenario.

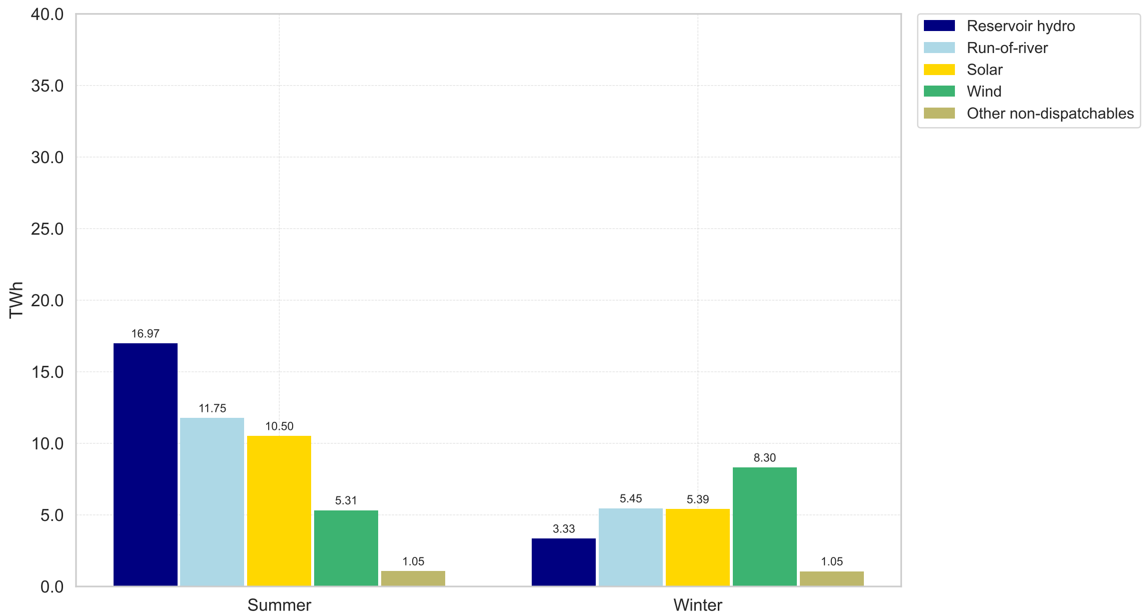



Figure 4.8.2: Seasonal renewable energy supply and hydro inflow in Switzerland in the Wind-focus scenario.

Solar generation exhibits a pronounced diurnal cycle and strong seasonality, while wind output is typically more dispersed over the day and less tightly concentrated in specific hours. These patterns are illustrated in Figures 4.8.1 and 4.8.2, which show the seasonal distribution of renewable energy supply in the Solar-focus and Wind-focus scenario, and in Figure 4.8.3, which reports the mean hourly capacity factors for solar and wind in Switzerland under the assumptions of this project (weather year 2009 from the TYNDP data package with capacity factors adjusted to Table 3.4.2).

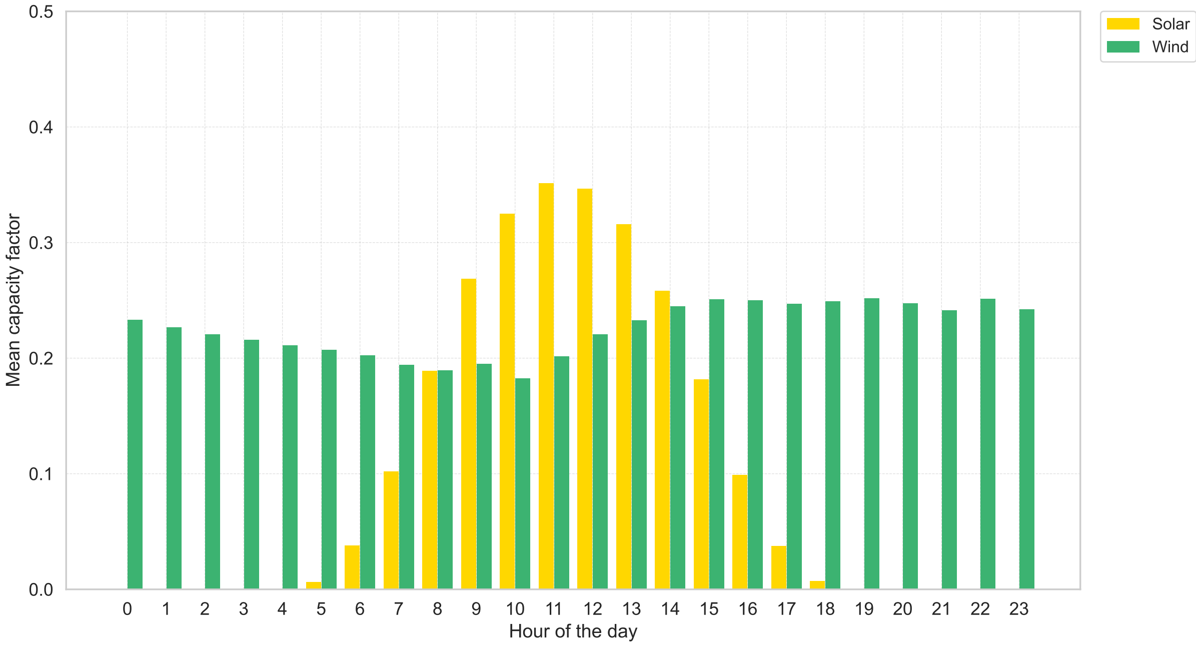



Figure 4.8.3: Mean capacity factors at hourly resolution in Switzerland for the weather year 2009 under Axpo assumptions.

Solar power exhibits a pronounced daily and seasonal pattern, as its output is concentrated in daylight hours and towards the summer months. This creates two structural issues. First, it generates significant intraday variability with high midday output. Second, in high-solar configurations, it produces large seasonal surpluses in summer that must somehow be transferred to winter if solar is expected to contribute materially to seasonal adequacy. As a result, solar-dominated scenarios require significant short-term flexibility (to shift energy from midday to peak hours) and, if winter supply is to be secured, a substantial amount of seasonal storage capacity.

To assess the feasibility of seasonal shifting within the modeled framework, we analyze the Solar-focus quasi-autarky scenario, where imports are expensive and therefore the system must balance itself to the maximum extent. The central question is whether abundant summer solar production can be stored and later used in winter through existing hydro reservoirs and PHS plants. Figure 4.8.4 shows the annual dispatch for this scenario and presents considerable summer curtailment (purple area), indicating that surplus solar energy exceeds the system's ability to absorb it through demand, pumping, or electrolysis (as it was already shown in Figure 4.2.2 and briefly discussed in Section 4.2). Figure 4.8.5 confirms this result in aggregated form, showing a total curtailment (showed in the injection column) amounting to approximately 11 TWh. Thus, under the assumptions of this study, summer solar surpluses cannot be fully shifted into winter and must be curtailed if exports are not available.

By comparison, the Wind-focus scenario shows lower curtailment, as shown in Figure 4.8.6. Part of this is simply an energy volume effect (see Figures 4.8.1 and 4.8.2), as in the modeled Wind-

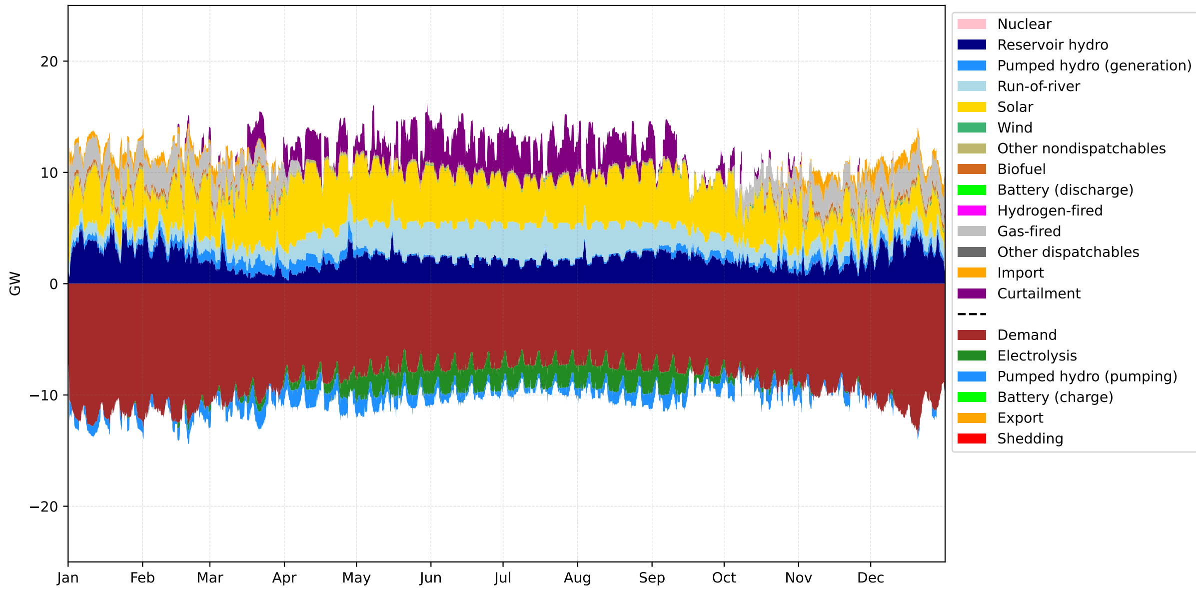



Figure 4.8.4: Annual energy dispatch (daily average) in Switzerland under the Solar-focus quasi-autarky scenario.

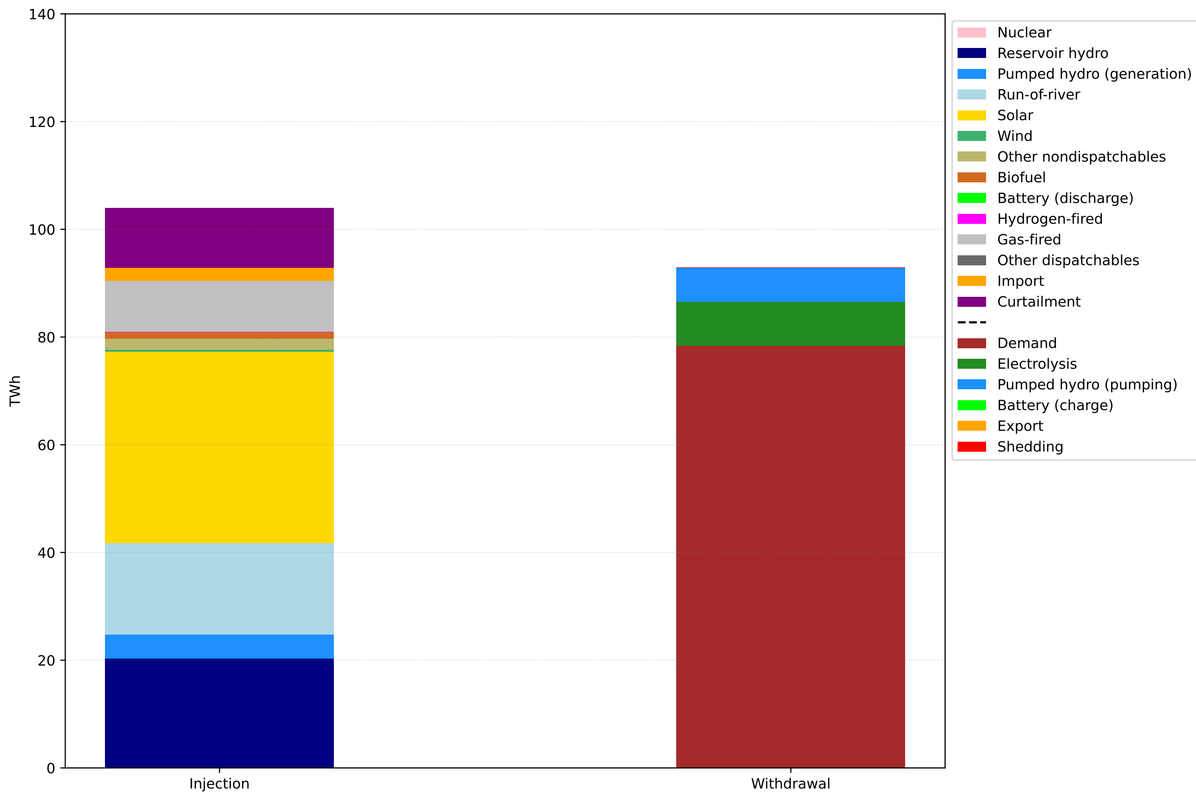



Figure 4.8.5: Annual energy dispatch (aggregation) in Switzerland under the Solar-focus quasi-autarky scenario.

focus scenario, total renewable generation (solar and wind together) is lower than in the Solar-focus scenario. However, the seasonal distribution of wind also matters, as wind contributes relatively more in winter than solar, which reduces the need to shift large summer surpluses across seasons and lowers both curtailment and the stress on seasonal storage.

The impact of large shares of solar energy is also visible in the operation of pumped storage plants,

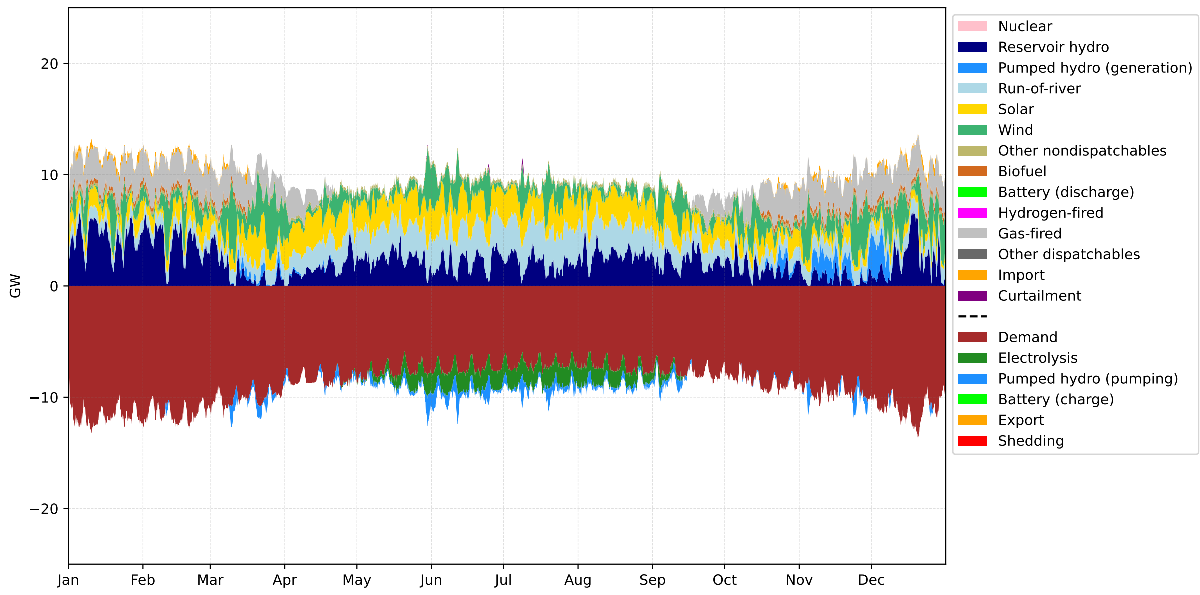



Figure 4.8.6: Annual energy dispatch (daily average) in Switzerland under the Wind-focus quasi-autarky scenario.

which acts as the primary short-term buffer against intraday variations. As solar production is concentrated around midday (Figure 4.8.3), it tends to trigger pumping precisely when generation peaks, as shown in Figure 4.8.7. Moreover, in Figure 4.8.8 (seasonal pumped energy in the quasi-autarky scenarios, previously shown with the corresponding seasonal generation in Figure 4.6.2), the Solar-focus scenario shows the highest pumping volumes both in summer and in winter. The Wind-focus scenario, in contrast, requires less pumping, particularly in winter, because wind generation is less concentrated into a small set of hours and creates fewer extreme daily surpluses. This operational difference becomes even clearer in Figure 4.8.7, where under the Solar-focus scenario, pumping is highly concentrated in the hours with strong solar production, while under the Wind-focus scenario pumping is more distributed across the day, reflecting its smoother generation profile.

*Overall, the results reinforce a key system-level insight: solar primarily drives short-term flexibility needs and increases summer surpluses, while wind contributes in a more "winter-supportive" way and leads to less severe intraday and seasonal imbalances. This does not imply that a solar-heavy system cannot ensure security of supply but it suggests that such a system would be more dependent on strong flexibility and balancing options, such as pumped storage utilization, potential hydro upgrades, interconnection capacity, imports, and other sources of flexibility to manage its pronounced temporal mismatches.*

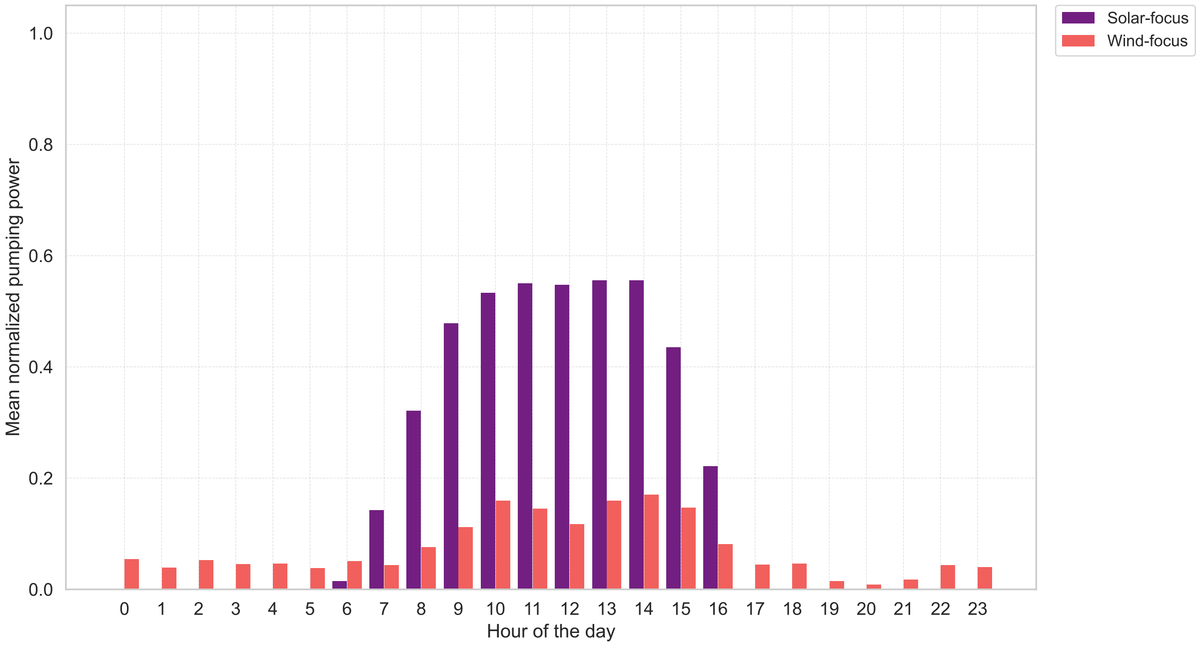



Figure 4.8.7: Mean hourly pumping power in the Solar-focus and Wind-focus quasi-autarky scenarios.

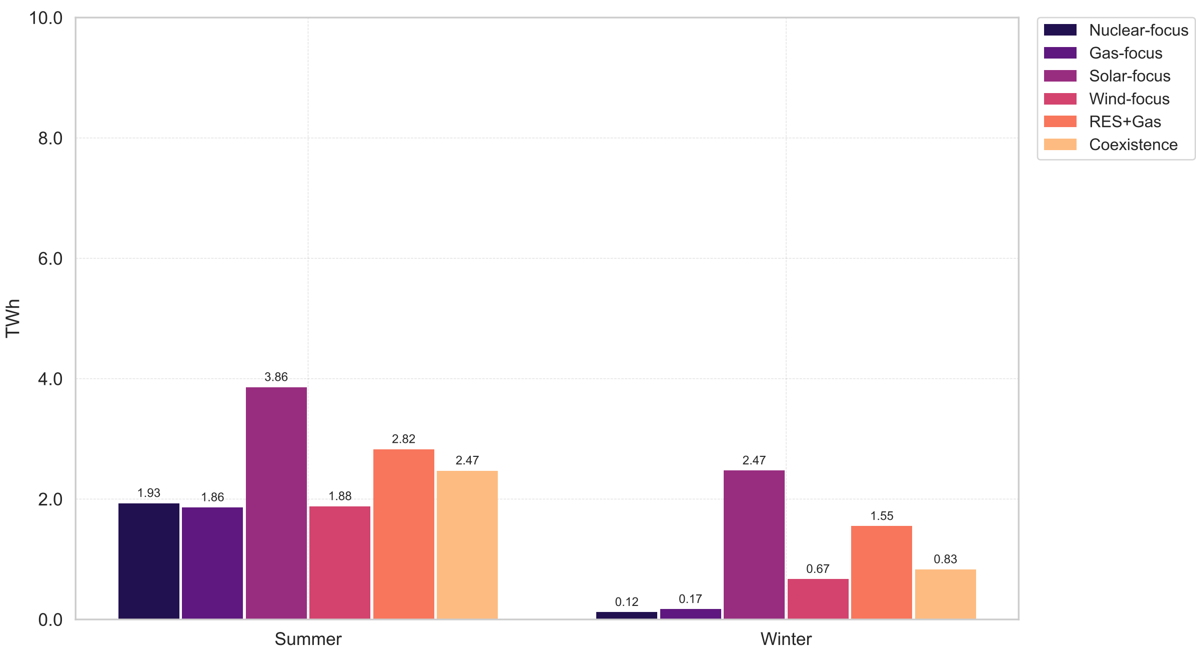



Figure 4.8.8: Seasonal pumped energy in Switzerland under the quasi-autarky scenarios.

## 4.9 The role of dispatchable technologies

Dispatchable technologies, particularly gas-fired units and nuclear power plants, play a central role in reducing Switzerland's exposure to winter imports. In fact, under the assumptions of this study (specifically the annual electricity demand in Switzerland around 78 TWh without electrolysis and the assumed installed renewable capacities), it would be impossible to keep the import exposure in winter to less than 5 TWh without dispatchable capacity. This is clear when the quasi-autarky scenarios are analyzed. Figures 4.9.1 and 4.9.2 present the seasonal generation from gas and nuclear plants for the quasi-autarky scenarios. It is clear that, without dispatchable production, Swiss net imports in winter (see Figure 4.3.1 for seasonal net imports in quasi-autarky scenarios) would rise above the 5 TWh threshold considered in this study.

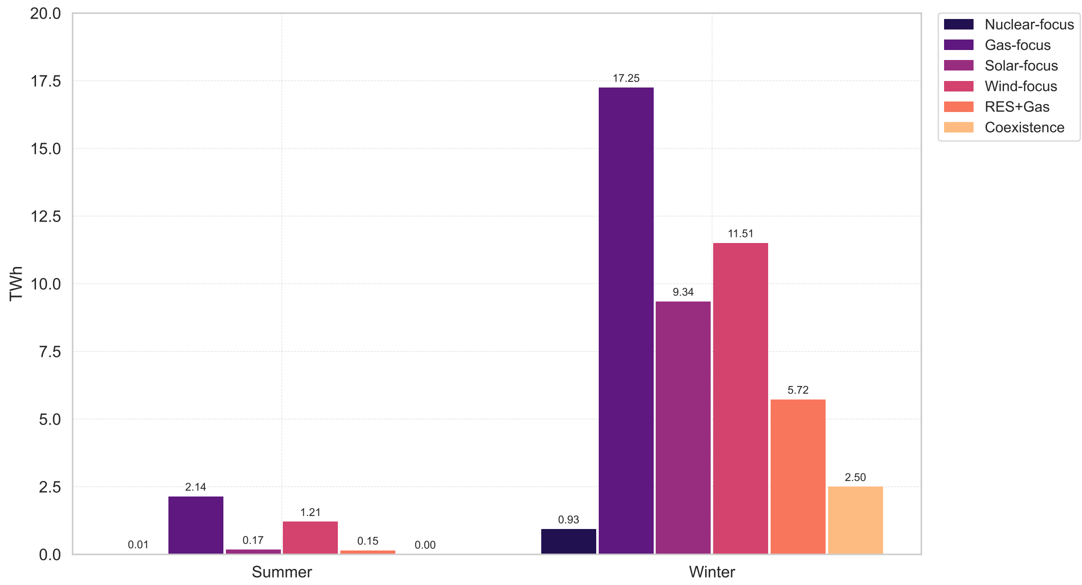



Figure 4.9.1: Seasonal gas-fired plants production in the quasi-autarky scenarios.

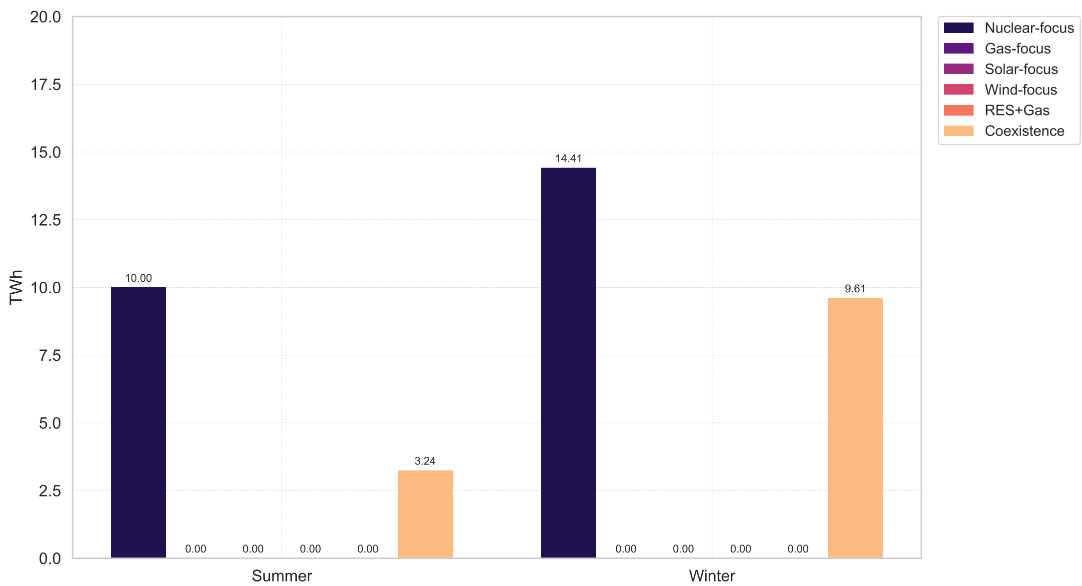



Figure 4.9.2: Seasonal nuclear plants production in the quasi-autarky scenarios.

At the same time, the value of dispatchable capacity cannot be assessed only through the lens of winter security of supply. Once Switzerland is simulated within the broader European electricity system, the actual utilization of these assets becomes strongly shaped by market conditions and marginal generation cost. Dispatchable units provide controllable output that covers residual demand when renewable generation is low, hydro flexibility is constrained, or imports are limited or uneconomic. However, how often these plants operate depends largely on the conditions in Europe.

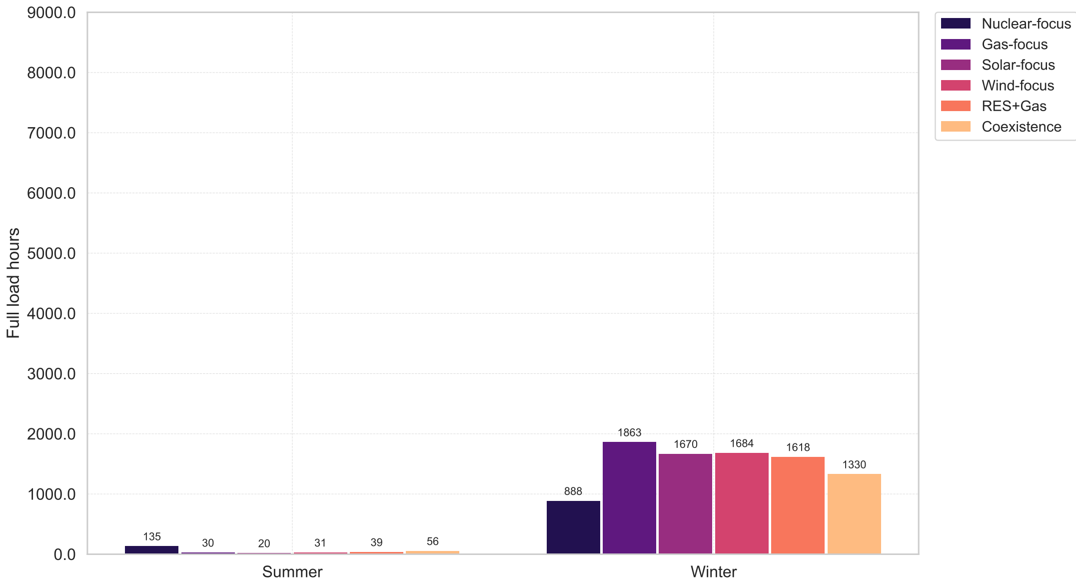



Figure 4.9.3: Seasonal equivalent full load hours of gas-fired plants (including old existing plants, new gas-fired plants, and new plants with CCS technologies) in the market-integrated scenarios.

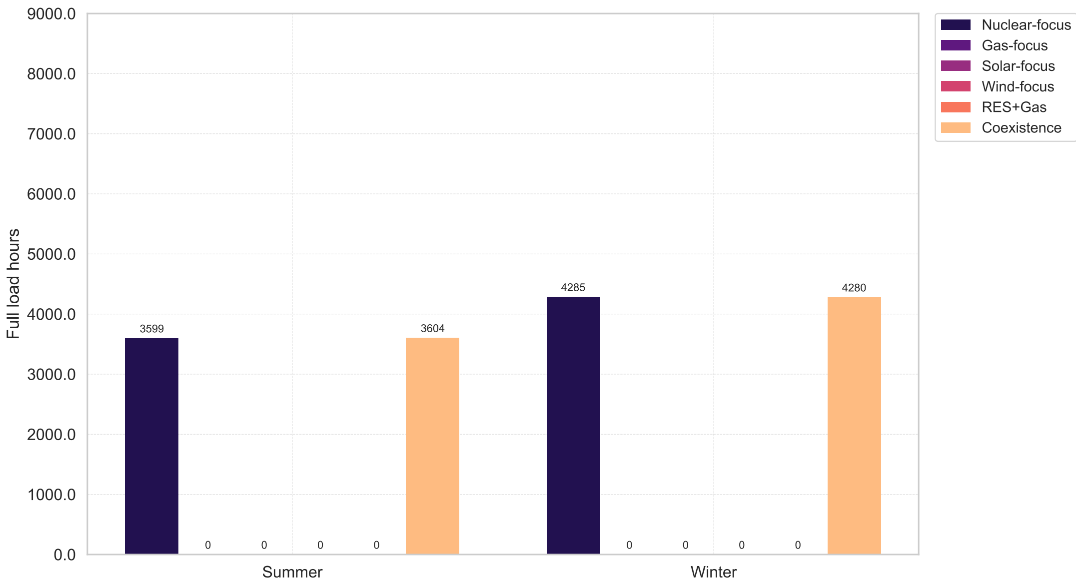



Figure 4.9.4: Seasonal equivalent full load hours of nuclear plants in the market-integrated scenarios.

When European renewable output is scarce and electricity prices are high, Swiss gas plants may run frequently, supplying domestic demand and potentially exporting, especially when their marginal costs sit below other European price-setting technologies. Conversely, when European renewable

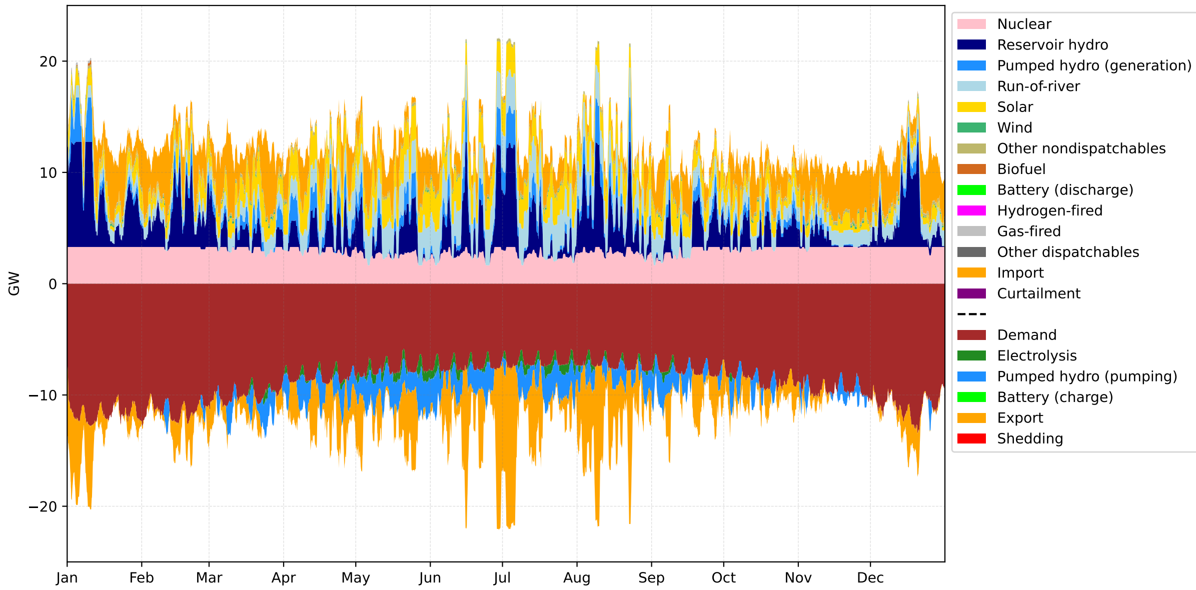



Figure 4.9.5: Annual energy dispatch (daily average) in Switzerland under the Nuclear-focus market-integrated scenario.

generation is abundant and energy prices are low, gas plants could be dispatched much less. In practice, across the assumed scenarios, total dispatched energy varies with installed capacity, but equivalent full-load hours can remain broadly similar because they are primarily driven by European residual demand patterns rather than Swiss conditions alone. For example, in the market-integrated scenarios, as shown in Figure 4.9.3, we can observe that the gas-fired power plants[9] run mostly in winter and for a limited amount of equivalent full load hours.

Nuclear plants, where present, tend to operate at high utilization throughout the year thanks to their low marginal generation cost, as shown in Figure 4.9.4. They function not only as an energy source in winter but also support electrolysis, PHS operations, and exports when conditions are favorable. While nuclear generation could, in principle, face more competition from cheaper renewable production in summer, the scenarios analyzed here still show significant nuclear dispatch during summer (see Figure 4.9.5 for an illustrative dispatch example) because its output is also absorbed by flexible demand (notably electrolysis and DSR) and storage, and because it can contribute to the wider European energy balance. Alternative configurations, such as lower electrolysis deployment combined with very high summer renewable output, could lead to different operating patterns and more frequent competition between nuclear and renewables and possibly to significant nuclear modulation.

*Overall, these results highlight a core trade-off: while dispatchable capacity might be crucial for winter security of supply, its actual dispatch pattern can be largely determined by market-driven conditions that may imply low utilization under normal conditions. This makes it essential to evaluate investments in dispatchable capacity not only against security of supply needs, but also against the balance between capital costs for keeping dispatchable capacity available and operating revenues driven by energy dispatch.*

[9] Combining old existing plants, new assets, and new plants with CCS technologies.

## 4.10 The role of the European transition

The results presented thus far rely on Axpo assumptions regarding the evolution of the European power system, characterized by a substantial expansion of renewables complemented by significant dispatchable capacity, notably gas- and hydrogen-fired generation. In this section, we contrast these findings with an alternative European pathway derived from the TYNDP data package (see Section 3.2), which features a more pronounced expansion of renewable capacity, in particular solar generation, higher nuclear capacity but considerably lower gas-fired capacity.

The objective is to assess how the broader European transition, captured here by a system with higher penetration of low-marginal-cost technologies and lower gas-fired capacity, affects the operation of the Swiss power system. The analysis focuses on two outcomes that are particularly sensitive to European conditions: (i) Switzerland's import–export dynamics and (ii) the dispatch and seasonal operation of reservoir hydropower.

For illustration, Figure 4.10.1 shows the annual European dispatch under the TYNDP scenario (combined with the RES+Gas scenario in Switzerland). Relative to the reference case (Figure 4.3.6 in Section 4.3), the European generation mix exhibits a markedly higher share of renewables, driven primarily by increased solar output.

Figure 4.10.2 compares seasonal injections and withdrawals in Switzerland under the Reference and TYNDP European scenarios. Several systematic differences emerge as a consequence of the more abundant low-cost generation in Europe. During summer, Switzerland experiences lower exports, reflecting reduced price differentials with neighboring markets, alongside higher electricity consumption for electrolysis and increased curtailment in solar-dominated scenarios. In winter, the system shifts towards higher imports and a reduced dispatch of domestic gas-fired generation, indicating that external supply becomes more competitive during scarcity periods.

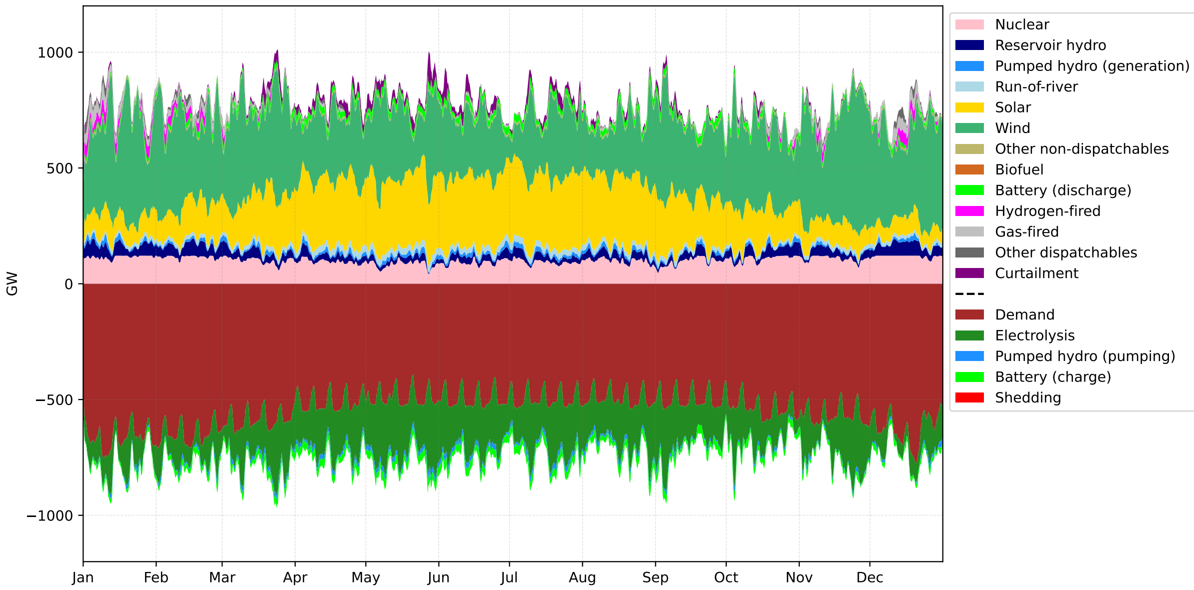
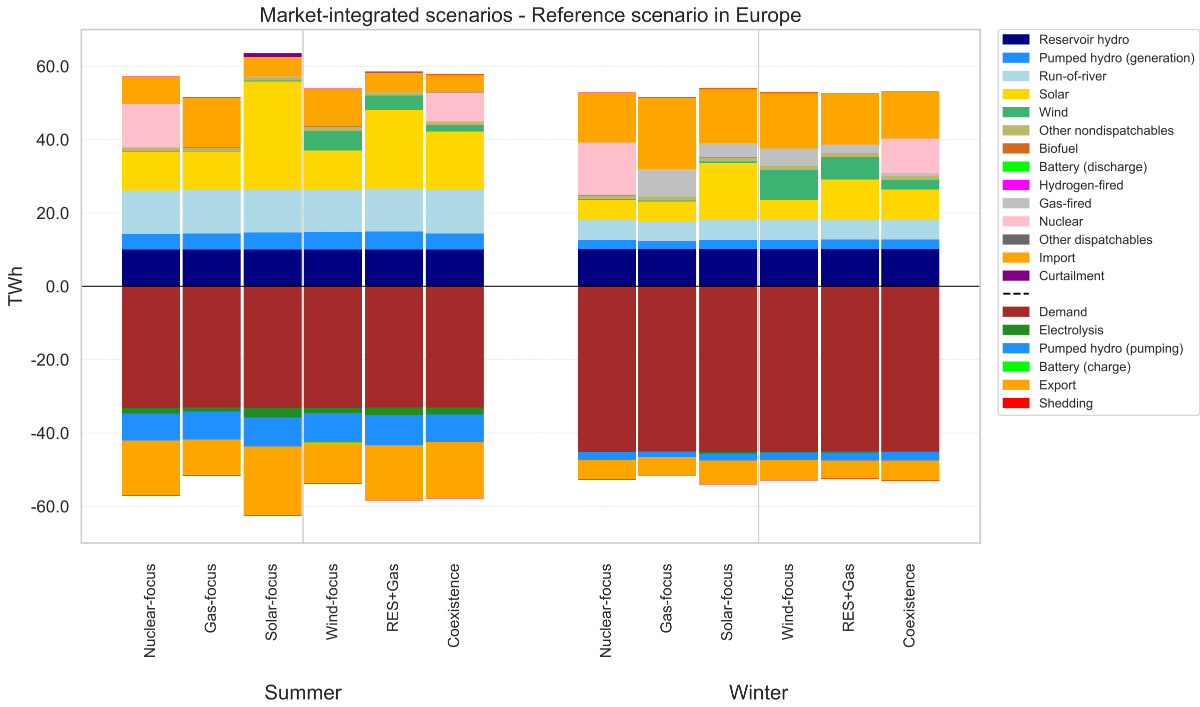



Figure 4.10.1: Annual energy dispatch (daily average) in Europe under the market-integrated conditions with the TYNDP scenario. The RES+Gas scenario in Switzerland is used for illustrative purposes.

Figure 4.10.3 quantifies these effects in terms of seasonal net imports. Across all scenarios, winter imports are significantly higher under the TYNDP case, with the highest increase observed in config-



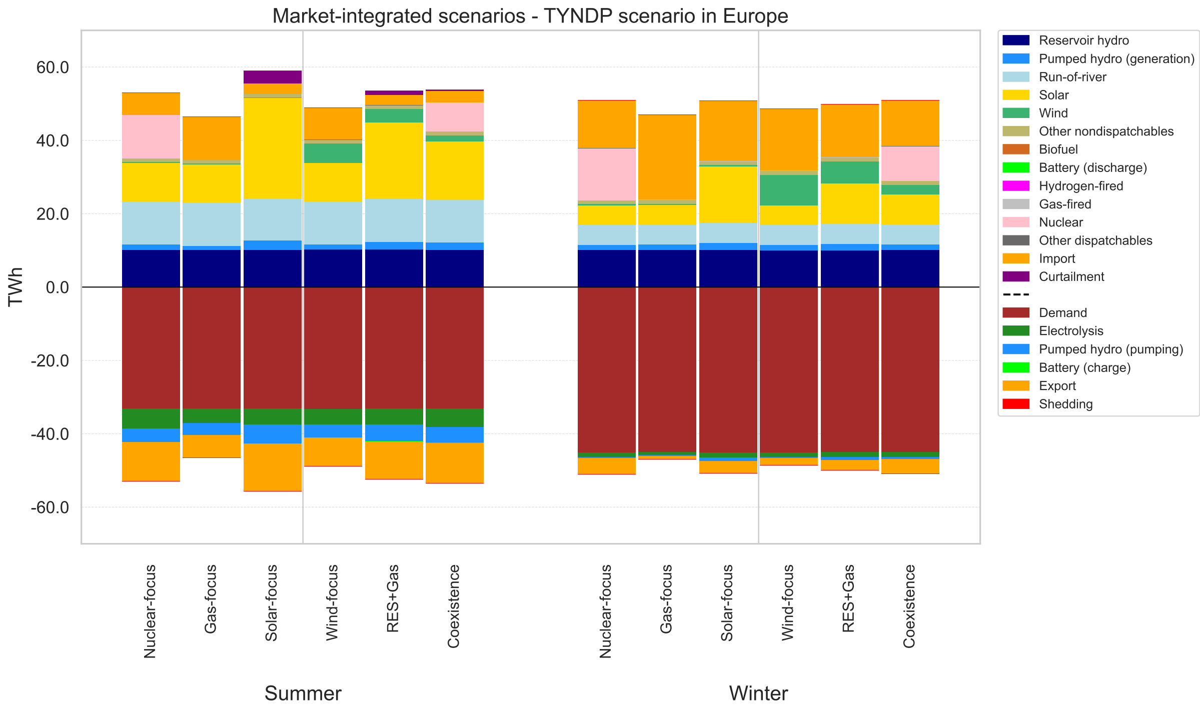
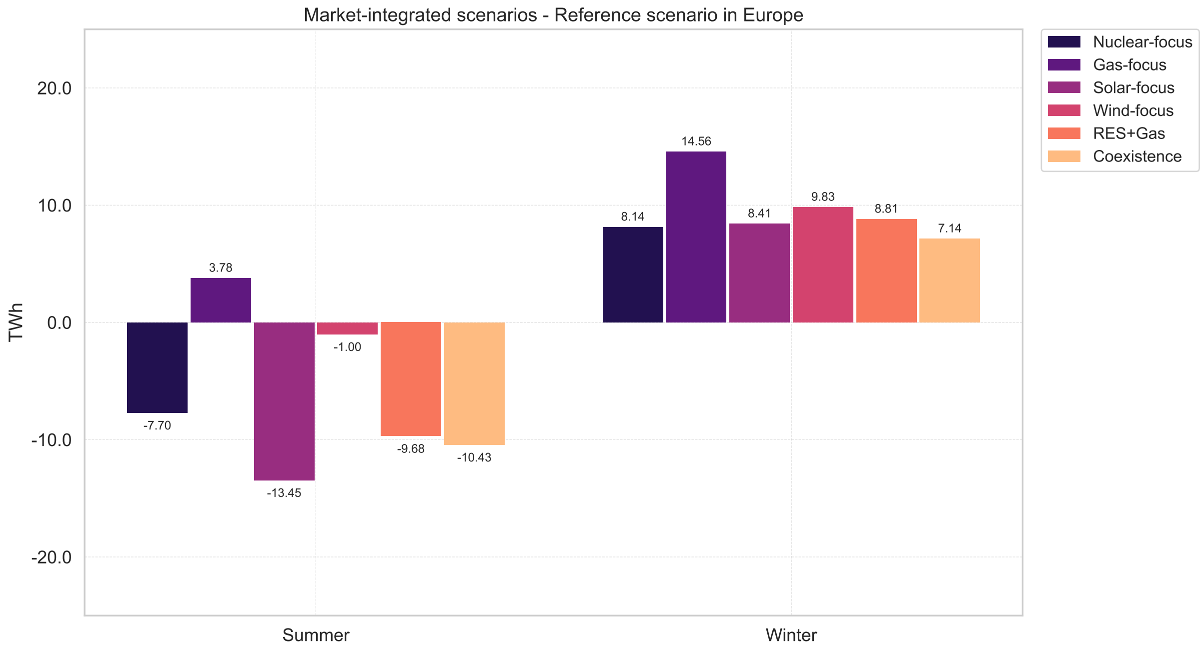




Figure 4.10.2: Seasonal injections and withdrawals in Switzerland with the Reference scenario (above) and TYNDP scenario (below) in Europe.

urations without nuclear capacity. The primary driver is the greater availability of low-cost electricity in Europe, particularly during periods of high renewable output, which translates into more frequent and economically attractive import opportunities. As a result, Switzerland relies more heavily on imports to meet winter demand, while the utilization of domestic dispatchable generation, especially gas-fired plants, declines. Similarly, in summer, exports decrease (or imports increase), as the abundance of low-cost renewable generation across Europe reduces the competitiveness of Swiss exports in neighboring markets.



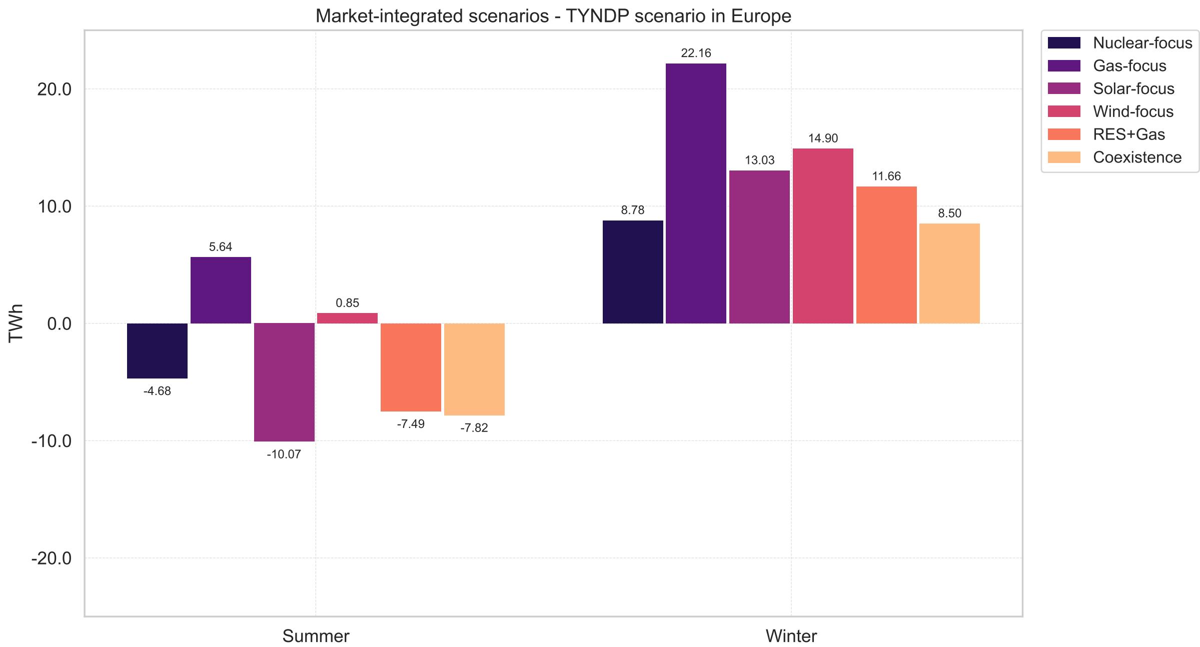




Figure 4.10.3: Seasonal net import of electricity in Switzerland in the six scenarios under the market-integrated scenarios with the Reference scenario (above) and TYNDP scenario (below) in Europe.

The implications for reservoir hydropower are shown in Figures 4.10.4 and 4.10.5. Reservoir plants continue to provide substantial seasonal energy shifting, but their winter generation is slightly reduced compared to the reference case (Figure 4.4.2 in Section 4.3), amounting to approximately 10.1 TWh across scenarios. This indicates that part of the winter demand is effectively substituted by imports, reducing the need to draw down domestic storage. On a monthly basis, the overall dispatch profile remains relatively stable, with differences across scenarios concentrated in winter months.

*Overall, these results reinforce the central role of European system conditions in shaping Swiss power system outcomes. A European transition characterized by very high renewable penetration increases the amount of low-price import opportunities. This, in turn, shifts the optimal balance be-*

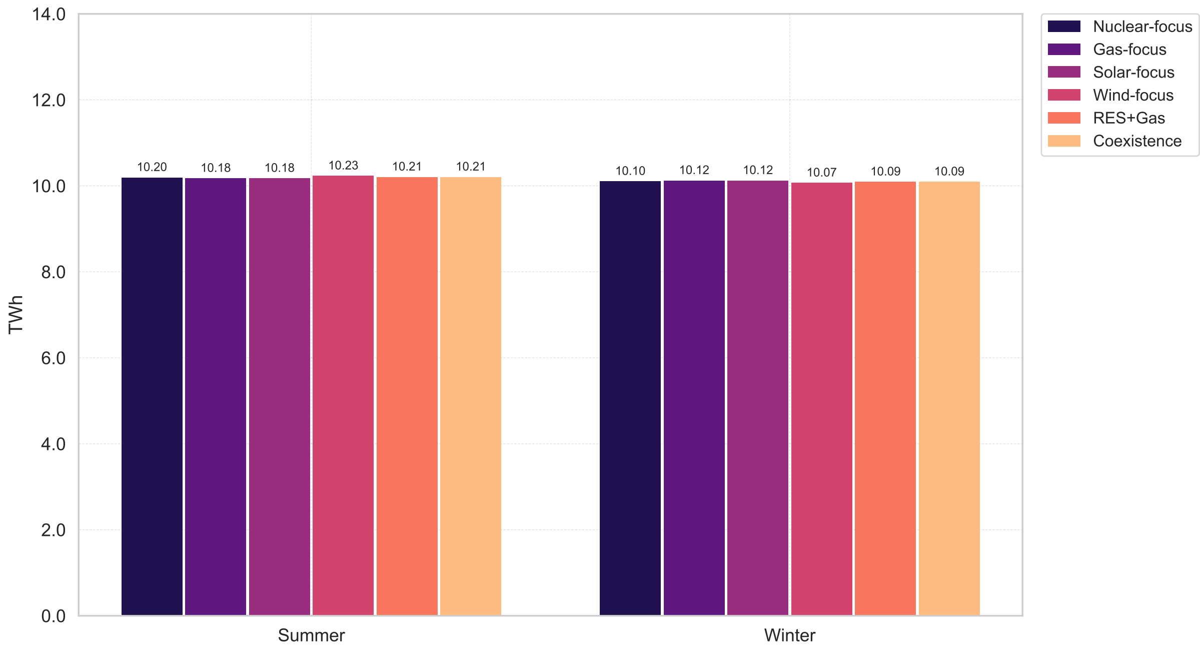



Figure 4.10.4: Seasonal production of reservoir hydropower plants in Switzerland under the TYNDP market-integrated scenarios.

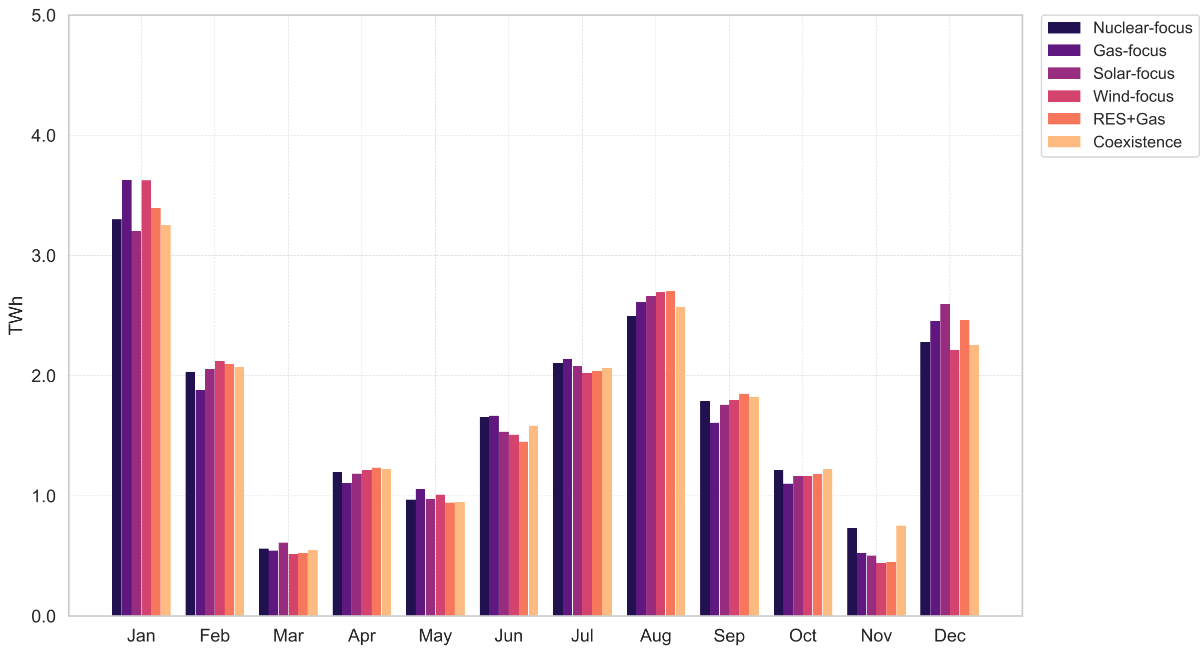



Figure 4.10.5: Monthly production of reservoir hydropower plants in Switzerland under the TYNDP market-integrated scenarios.

*tween domestic generation, storage, and cross-border exchanges. While Swiss flexibility, especially reservoir hydropower and storage, remains valuable, its role is partially reoriented: from primarily covering domestic scarcity towards arbitraging increasingly pronounced price differentials across seasons and between neighboring markets.*

## 4.11 The role of market integration

A key uncertainty regarding Switzerland's electricity sector is the degree of integration with the broader European electricity market. Market integration is important because Switzerland's operation in an interconnected system is not driven only by domestic conditions. In fact, as discussed in previous sections, cross-border exchanges provide access to low-cost generation abroad and enable Swiss hydropower to exploit its flexibility through arbitrage. Conversely, reduced interconnection limits trading opportunities and shifts the system towards a more domestically driven mode of operation.

In this section, we assess the sensitivity of Swiss dispatch to various levels of market integration using a stylized representation of reduced cross-border transfer capacity. Specifically, we scale down net transfer capacities (NTCs) between Switzerland and neighboringring countries to 75%, 50%, 25%, 10%, and 0% of their baseline values. This approach is often used in scenario studies because it provides a transparent and comparable way to quantify how tighter interconnection constraints can alter dispatch patterns. While this stylization does not capture all dimensions of market coupling, it is sufficient to perform a preliminary assessment of weaker cross-border connectivity.

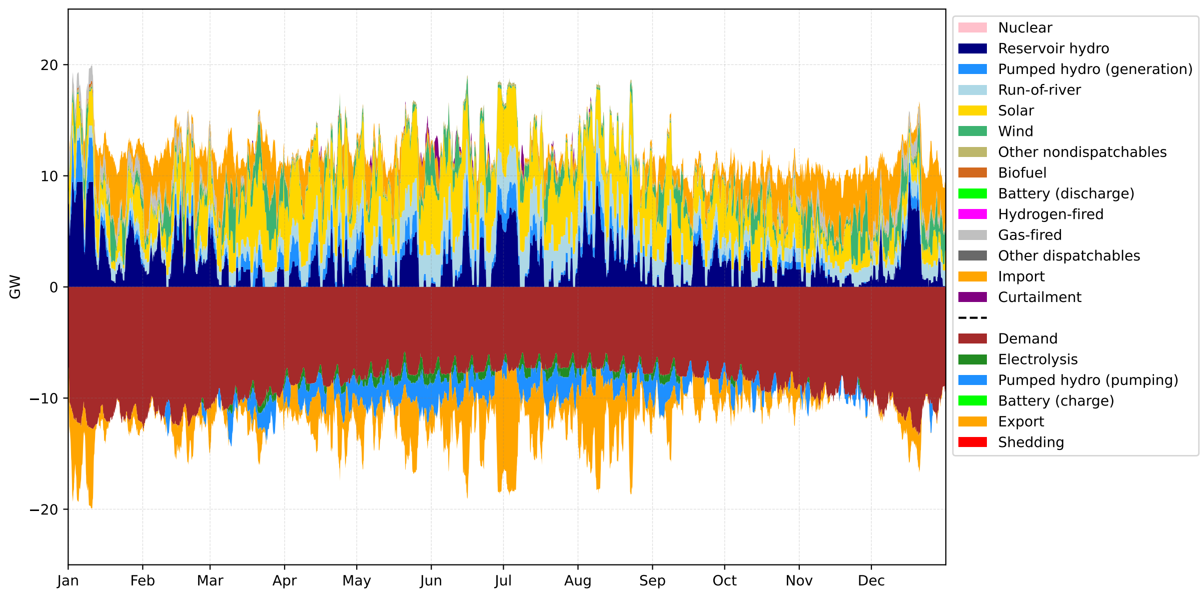



Figure 4.11.1: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario with NTCs reduced to 75%. The RES+Gas scenario in Switzerland is used for illustrative purposes.

Figures 4.11.1-4.11.5 show annual Swiss dispatch for the RES+Gas scenario under the aforementioned NTC assumptions. As expected, reducing NTCs leads to limited cross-border exchanges, as both imports and exports decline in magnitude. Two implications are of particular relevance.

First, net winter imports decrease as interconnections are reduced, as shown in Figure 4.11.6 (RES+Gas scenario shown for illustrative purposes). This is the direct consequence of a more limited access to foreign supply. In fact, when imports are constrained, the system must rely more frequently on domestic resources even in hours when importing would be economically attractive under full market integration. In other words, lower net imports under reduced NTCs indicate reduced exchange capability. A similar effect can be observed in summer with the gradual reduction of the net export position of Switzerland.

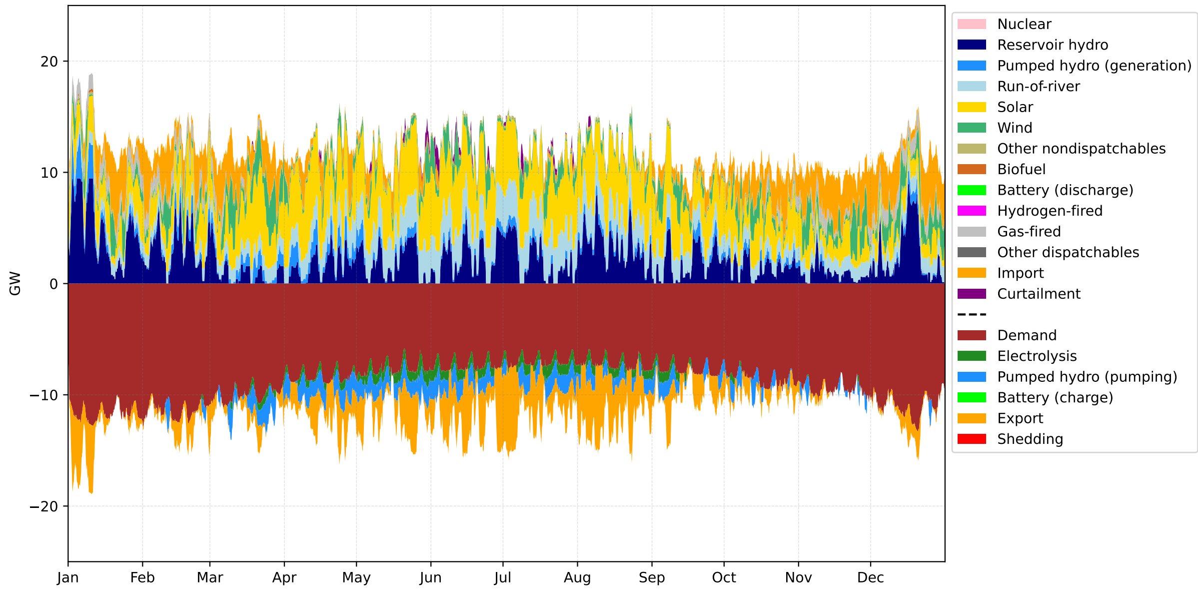



Figure 4.11.2: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario with NTCs reduced to 50%. The RES+Gas scenario in Switzerland is used for illustrative purposes.

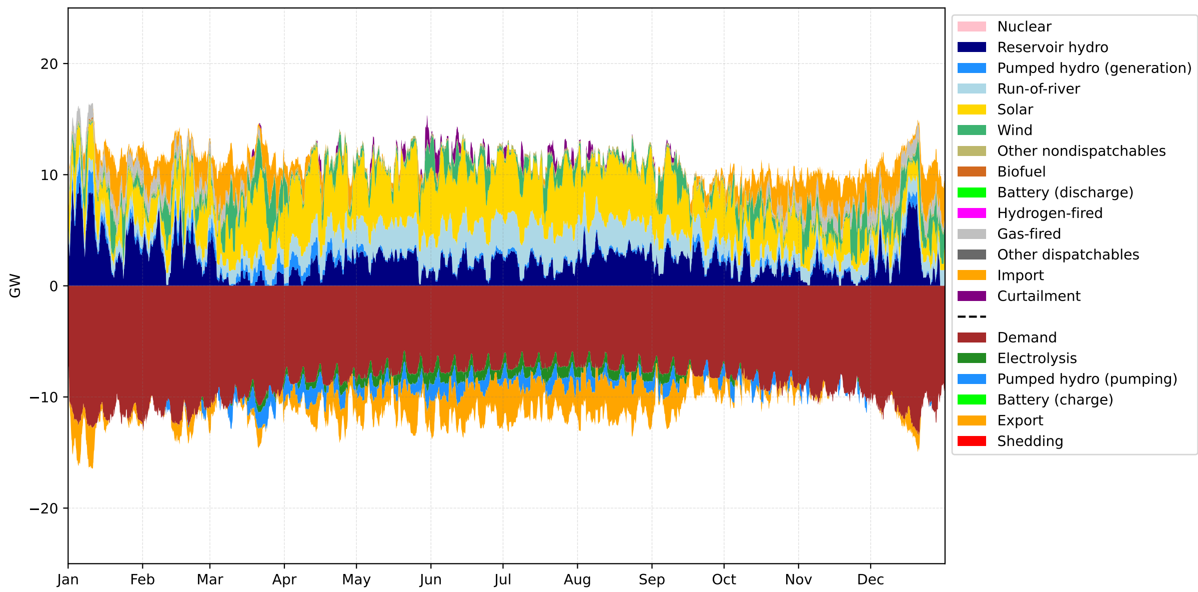



Figure 4.11.3: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario with NTCs reduced to 25%. The RES+Gas scenario in Switzerland is used for illustrative purposes.

Second, the operation of reservoir hydropower plants changes in terms of dispatch pattern. With NTCs fully available, reservoir hydro dispatch shows pronounced peaks associated with export periods and reduced generation when imports are attractive. As NTCs are reduced, these arbitrage-driven peaks become less pronounced and hydro dispatch becomes smoother (Figures 4.11.1-4.11.5). In other words, reservoir hydro shifts towards serving Swiss domestic needs rather than functioning as a flexibility interface with the other European countries. This is consistent with the broader interpretation that hydropower simultaneously supports seasonal shift and short-term flexibility, but the relative weight and pattern of these roles depends on the degree of market integration.

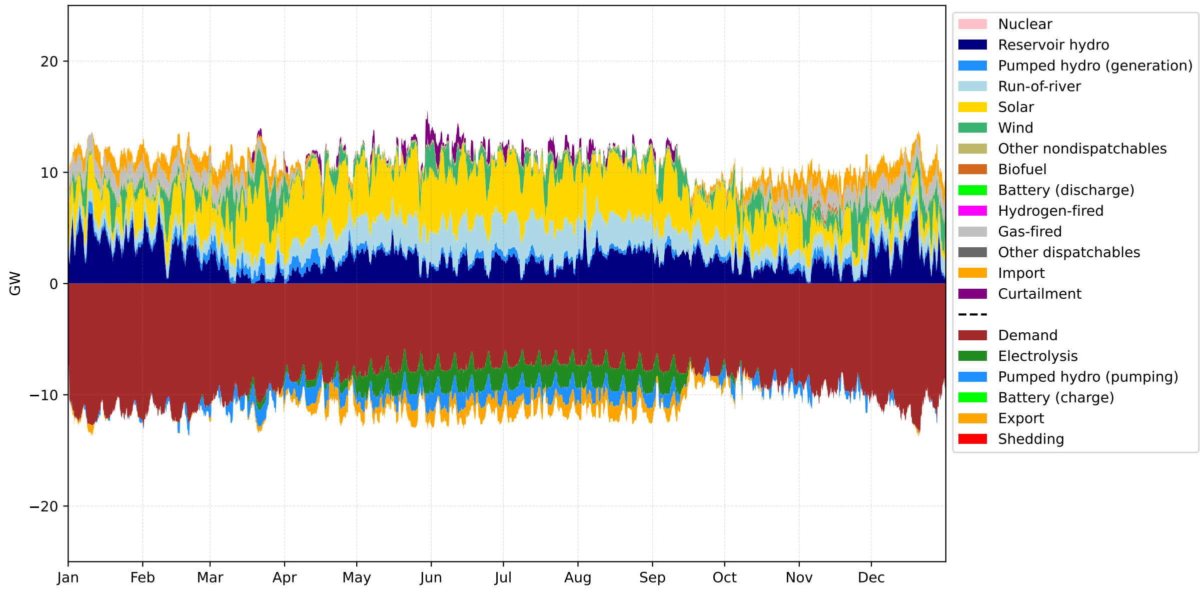



Figure 4.11.4: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario with NTCs reduced to 10%. The RES+Gas scenario in Switzerland is used for illustrative purposes.

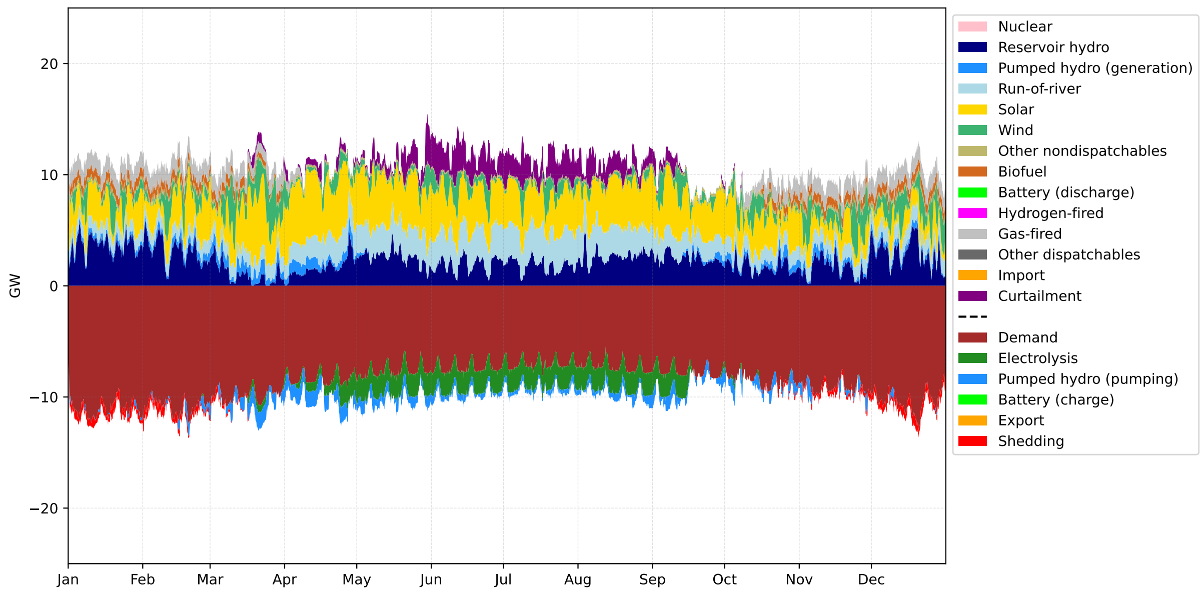



Figure 4.11.5: Annual energy dispatch (daily average) in Switzerland under the market-integrated scenario with NTCs reduced to 0%. The RES+Gas scenario in Switzerland is used for illustrative purposes.

The reduction in imports is compensated mainly by increased utilization of domestic dispatchable resources (and, to a lesser extent, by reduced exports and higher curtailment in surplus periods). In the case of 0% NTC, the dispatch outcome converges towards the quasi-autarky scenarios[10], where Switzerland becomes effectively isolated from European price formation, cross-border balancing is unavailable, and domestic dispatchable generation plays a larger role in covering winter residual demand.

[10]The amount of net imports in the quasi-autarky scenarios correspond to the amount of load shedding in the 0% NTC scenarios.

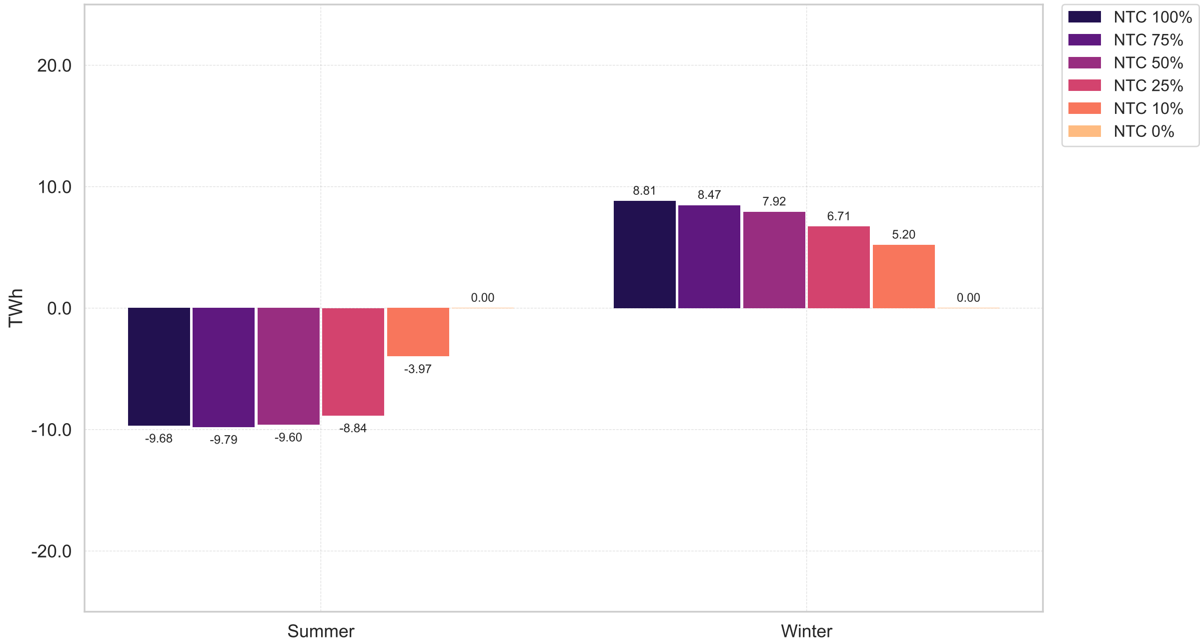



Figure 4.11.6: Seasonal net imports for the RES+Gas scenario with reduced NTCs.

The policy implication is straightforward. *A less integrated market may reduce imports as a market outcome, but it simultaneously increases the value, and potentially the required volume, of domestic dispatchable capacity and flexibility. Therefore, adequacy and capacity discussions should take into account the assumed level of market integration, since the same domestic portfolio can lead to different import levels and dispatch patterns under different interconnection assumptions.*

## 4.12 The role of transmission grid constraints

In this final section, we briefly assess the role of internal transmission grid constraints within Switzerland. Specifically, we aim to verify if they can affect the dispatch results and the interpretation of winter security of supply. This evaluation is performed only with the market-integrated simulation setting. The objective is not to provide a detailed grid assessment, nor to optimize nodal demand allocation or technology siting. The main goal is to use a representative transmission topology, along with a plausible spatial distribution of demand and generation, to assess if internal bottlenecks could create major operational issues (e.g. significant load shedding) or qualitatively change the aggregate dispatch pattern observed in the single-node Switzerland model.

The representative grid is adapted from the network dataset developed in the Nexus-e project [11]. It is based on the current Swiss transmission system with selected updates, and it is combined with a nodal allocation of demand and generation technologies derived from the same source [11]. The resulting topology is shown in Figure 4.12.1.

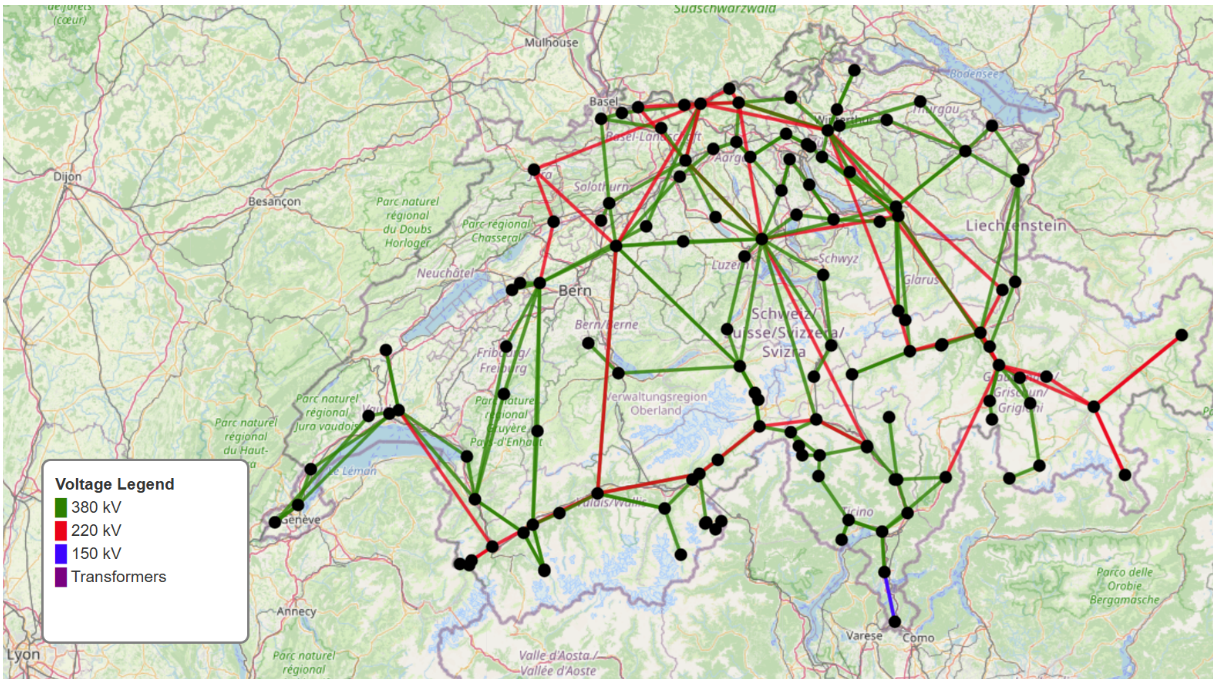



Figure 4.12.1: Topology of the Swiss transmission grid used in this study

Figure 4.12.2 reports annual Swiss dispatch for the RES+Gas scenario when Switzerland is represented with its nodal transmission system rather than as a single aggregated node. Compared with the corresponding single-node results (Figure 4.3.4), the nodal model exhibits smoother import and export peaks. For example, the export spike in July is less pronounced, and the import peak in November is reduced. This is consistent with the introduction of internal network constraints, as they limit the system's ability to respond to external price signals due to system constraints not captured by the NTC assumptions. As a consequence, flexibility that appears fully available in the aggregated model becomes partially constrained by internal network constraints, and part of the hydro-driven import-export patterns is smoothed.

However, the main qualitative patterns remain valid. The nodal model reproduces the same broad seasonal pattern observed previously, as Switzerland still imports during periods of abundant low-cost generation in neighboringring systems and exports during tighter regional conditions. Moreover,

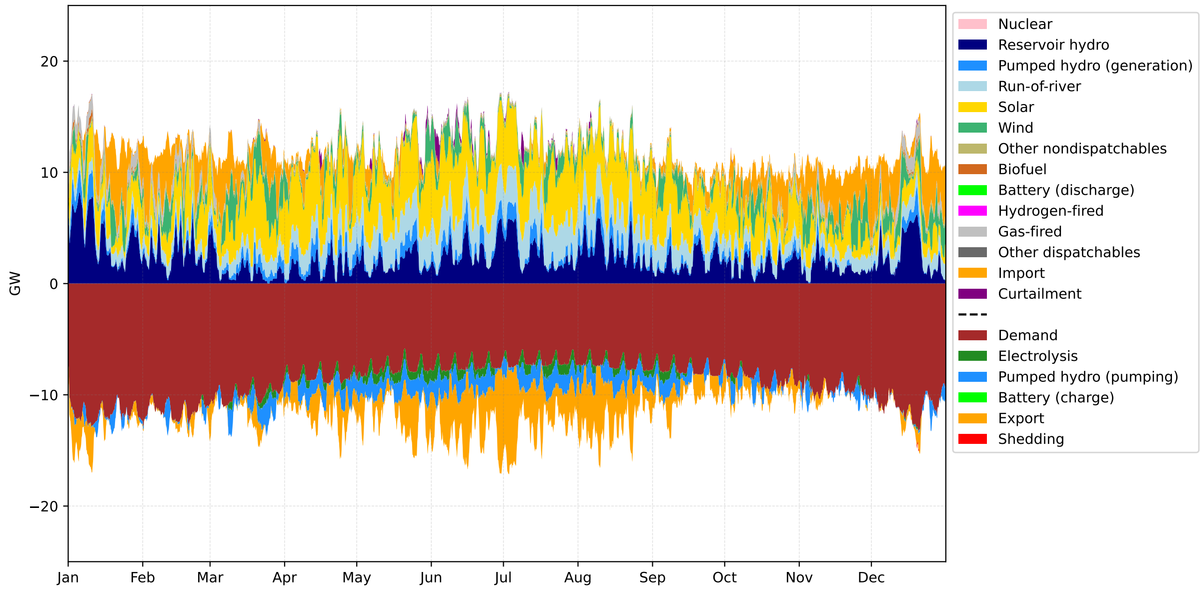



Figure 4.12.2: Annual energy dispatch (daily average) in Switzerland under the market-driven scenario with the transmission grid. The RES+Gas scenario in Switzerland is used for illustrative purposes.

reservoir hydro continues to play the same dual role (seasonal shifting and short-term flexibility). In other words, internal constraints act primarily as a moderating factor on the magnitude of cross-border trades rather than as a driver of fundamentally different system behaviour.

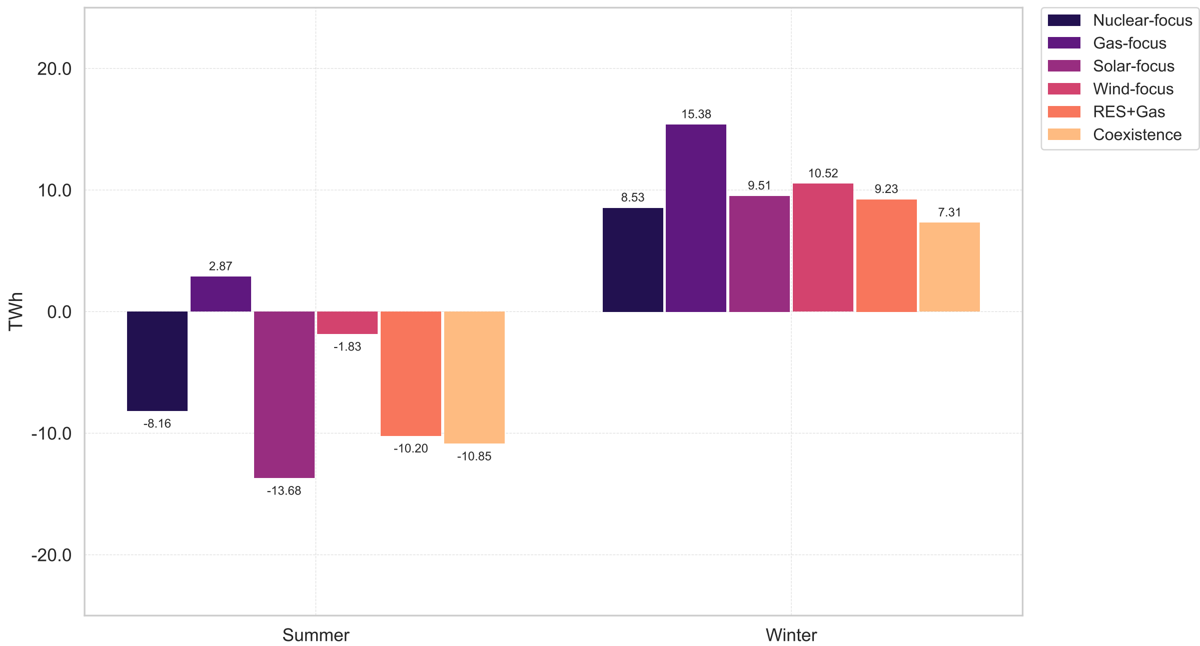



Figure 4.12.3: Seasonal net imports for the RES+Gas scenario with the transmission grid.

This conclusion is confirmed by the seasonal net import results. Figure 4.12.3 shows seasonal net imports for the nodal transmission case. Compared to the single node case (Figure 4.3.5 in Section 4.3), both winter net imports and summer net exports increase but remain within the same order of magnitude. In aggregated terms, the annual dispatch mix remains remarkably similar between the two representations (see Figures 4.12.4 and 4.12.5), with the main difference being a reduction in the volume of cross-border exchanges. Moreover, load shedding is negligible[11]. *This indicates that the representative Swiss network, as modeled here, does not introduce binding bottlenecks severe enough to alter the overall dispatch patterns of the simulated scenarios or to lead to different insights than the single node model.*

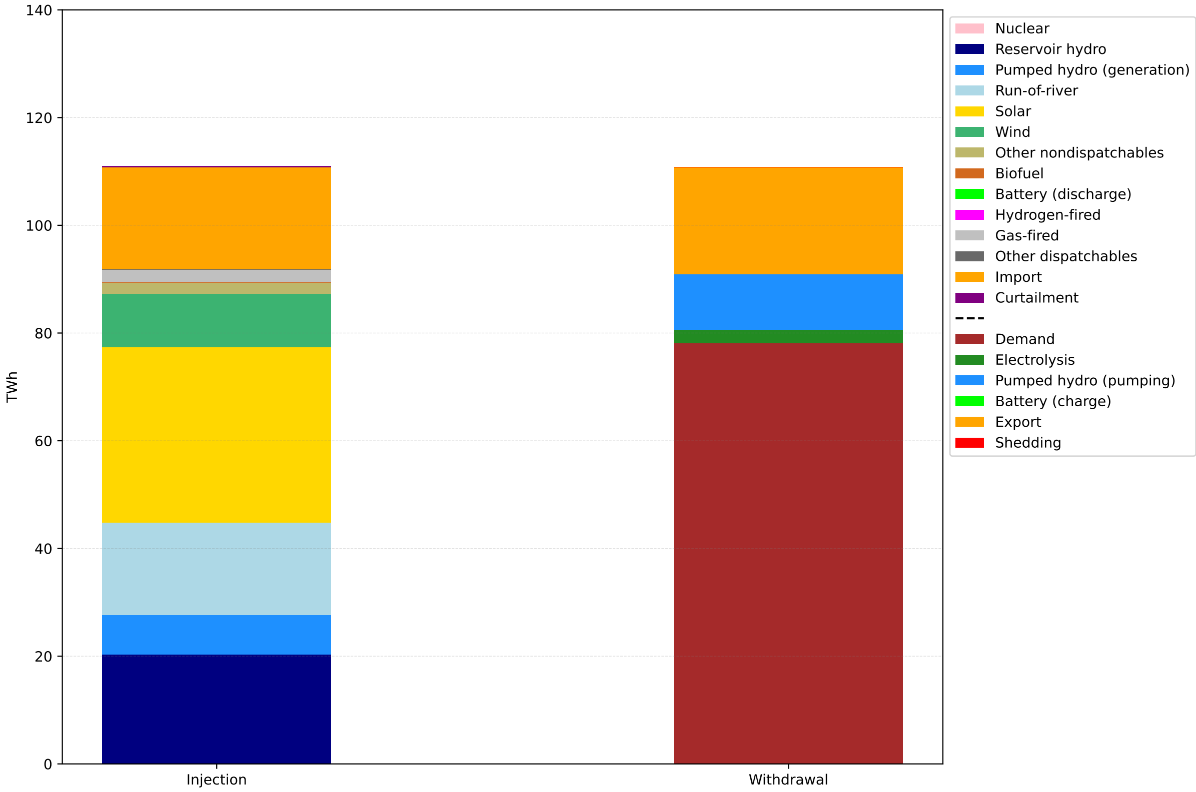



Figure 4.12.4: Annual energy dispatch (aggregated) in Switzerland under the market-driven scenario. The RES+Gas scenario in Switzerland is used for illustrative purposes.

Figure 4.12.6 provides additional evidence by showing the line loading heatmap. Most internal lines operate well below their thermal limits for most of the year. A limited subset of lines reaches high loading (often cross-border interconnectors and links connected to large hydropower plants). This pattern is intuitive, as cross-border exchanges concentrate stress on the corresponding interconnectors, while hydro plants can create localized high injections. Importantly, even where high loading occurs, it does not translate into widespread infeasibilities in the modeled operation.

*Overall, this nodal sensitivity suggests that introducing a more detailed Swiss transmission representation does not reveal major operational issues for the considered scenarios under the assumptions of this study. Internal constraints reduce the system's ability to fully exploit flexibilities and modify import/export trades, but the core dispatch pattern and the main conclusions are preserved. This should be interpreted as a robustness check rather than as a guarantee of transmission grid adequacy. The analysis relies on a representative network, stylized future updates, simplified operational modeling, and an assumed spatial allocation of demand and generation. A comprehensive grid assessment would require more detailed topology and reinforcement assumptions, contingency analysis, and a systematic exploration of alternative siting and distribution projections of demand.*

[11] Some localized nodal load shedding occurs. The volumes are negligible, and investigating its specific drivers is outside the scope of this study.

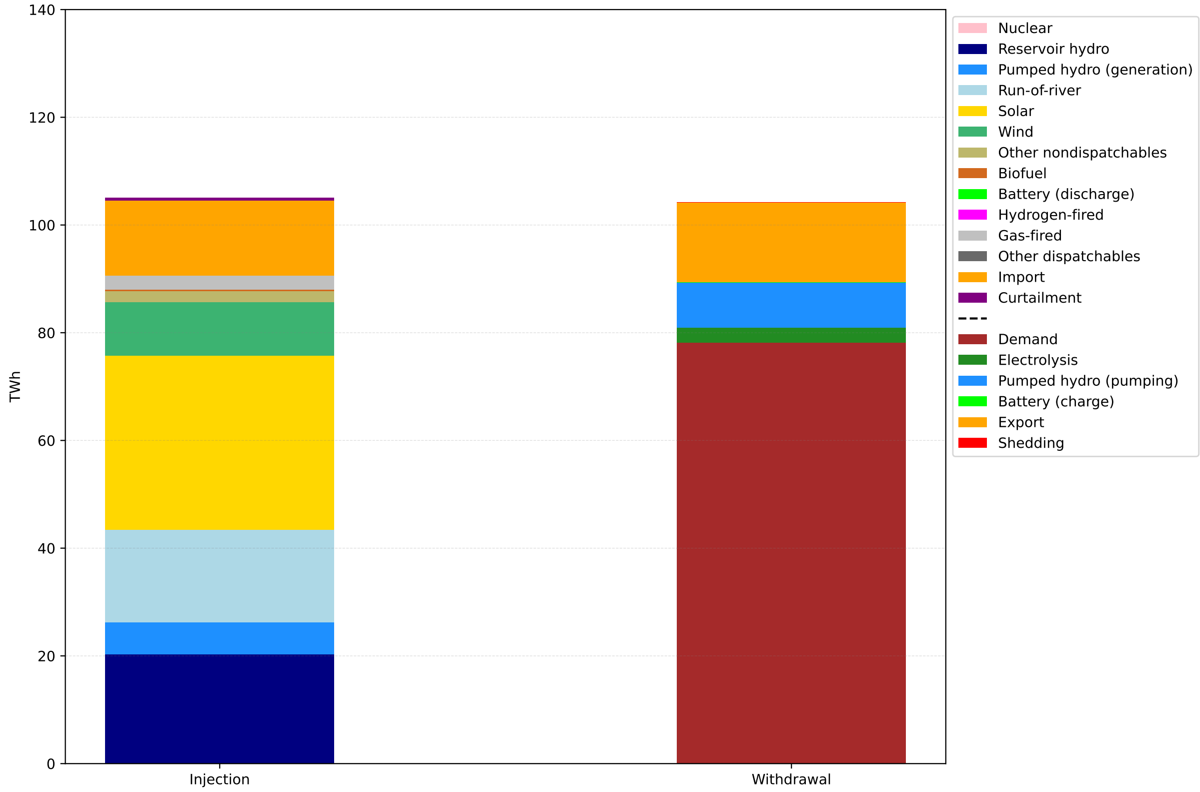



Figure 4.12.5: Annual energy dispatch (aggregated) in Switzerland under the market-driven scenario with the transmission grid included in Switzerland. The RES+Gas scenario in Switzerland is used for illustrative purposes.

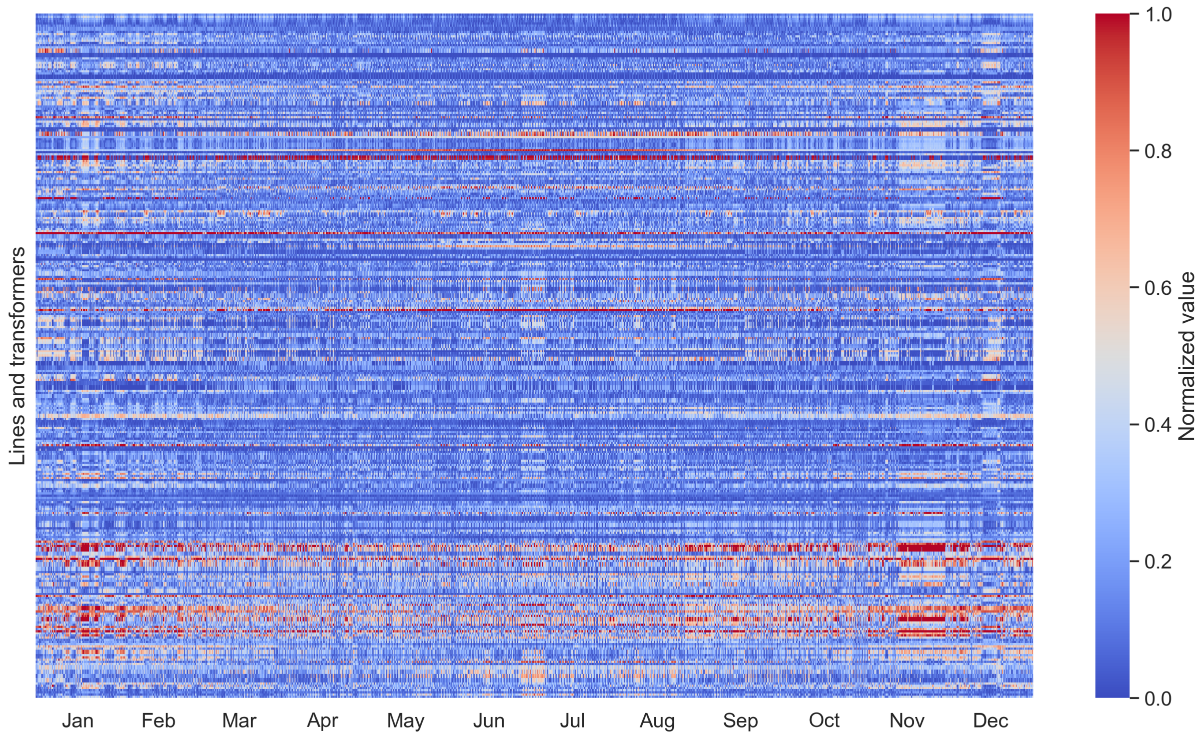



Figure 4.12.6: Line loading in the RES+Gas scenario.

# 5 Conclusion

## 5.1 Main findings and insights

This study provides a structured assessment of Switzerland's winter electricity supply across a range of long-term scenarios, with a particular focus on distinguishing between structural adequacy and market-driven outcomes. A central insight is that the winter gap cannot be reliably interpreted using net imports alone. In an integrated European electricity system, net imports primarily reflect economically efficient dispatch and cross-border price signals rather than a pure measure of supply dependence. A more robust and policy-relevant assessment therefore requires complementing observed net imports with structural winter import exposure, which captures the underlying adequacy of domestic resources.

Beyond this conceptual distinction, the analysis examines the role of key system components and drivers, including hydropower, renewable generation, dispatchable capacity, flexibility options, market integration, and transmission constraints. By evaluating how these elements interact across different scenarios and modeling assumptions, the study provides a system-level perspective on the determinants of winter supply security.

The main findings of this analysis are summarized below.

**Finding 1: The scenarios contain sufficient domestic capacity to limit structural winter import exposure to 5 TWh, but market-driven imports can be higher (see Section 4.3).**
Across all six Axpo scenarios, the quasi-autarky simulations indicate that Switzerland can limit structural winter import exposure to 5 TWh. Under the assumptions of this study, this suggests that the proposed portfolios provide sufficient domestic resources to meet winter demand with only limited reliance on external supply. However, under market-integrated conditions, winter net imports exceed this level in all scenarios. This divergence reflects economically efficient dispatch: Switzerland imports when electricity is cheaper abroad, even if domestic capacity is available. As a result, high winter imports should not be interpreted as a direct indicator of issues in the winter security of supply.

**Finding 2: Reservoir hydropower is a central pillar of winter security of supply through seasonal storage (see Section 4.4).**
Reservoir hydropower provides a substantial seasonal shift of energy from summer to winter, contributing roughly 7 TWh of shifted energy under the modeled conditions. This seasonal transfer plays a key role in limiting winter import exposure. Importantly, this behavior is observed consistently in both simulation settings (under quasi-autarky conditions and under market integration). This indicates that seasonal storage is not only essential from an adequacy perspective, but also economically attractive, as electricity tends to be more valuable in winter than in summer. Overall, the results suggest that reservoir-based seasonal storage is an intrinsic feature of the Swiss system and is effectively maximized under both adequacy-driven and market-integrated conditions.

**Finding 3: Reservoir hydropower also provides critical short-term flexibility and interacts strongly with European market dynamics (see Section 4.5).**
Beyond seasonal storage, reservoir hydro adjusts generation on shorter time scales in response to market signals. It reduces output and preserves water during periods of abundant and low-cost imports from Europe, and increases production during periods of scarcity, often supporting exports. This behavior allows Switzerland to act as a flexibility provider within the European system while simultaneously preserving resources for winter adequacy.

**Finding 4: Pumped hydro storage provides valuable short-term flexibility and can contribute to longer-term energy shifting under certain conditions (see Section 4.6).**
Pumped hydro storage (PHS) plays a key role in balancing short-term fluctuations by shifting energy across hours and days, particularly in systems with high shares of variable renewables. In the model, PHS also contributes to inter-seasonal shifting to some extent, although this should be interpreted as a technical potential rather than a guaranteed real-world operating mode.

**Finding 5: Additional flexibility from batteries and demand-side response has limited impact on seasonal balances (see Section 4.7).**
Batteries and demand-side response (DSR) have only a limited impact on seasonal net imports and the overall winter energy balance in the market-integrated simulations. This reflects the dominant role of hydropower and cross-border interconnections, which already provide substantial flexibility.
Under more constrained (quasi-autarky) conditions, these resources help reduce temporal mismatches between supply and demand and can lower winter import needs, particularly in renewable-dominated scenarios. However, within the scope of this study, they do not appear essential to meet the targeted level of winter adequacy.

**Finding 6: The contribution of renewable generation depends strongly on its temporal profile (see Section 4.8).**
Solar and wind generation affect the system differently. Solar-dominated scenarios produce large daily mismatches and summer surpluses that cannot be fully shifted to winter, leading to curtailment or increased reliance on exports. This increases the need for both short-term and seasonal flexibility. Wind generation, by contrast, is more evenly distributed and contributes relatively more during winter, reducing seasonal imbalances. As a result, wind can support winter adequacy more directly, while solar requires stronger flexibility and system integration.

**Finding 7: Dispatchable technologies are essential for limiting winter import exposure, but their utilization depends on market conditions (see Section 4.9).**
Gas-fired and nuclear generation play a critical role in covering residual demand during periods of low renewable output and are necessary to maintain winter adequacy. However, under the simulated market-integrated conditions, their utilization is strongly influenced by European price signals. Gas plants tend to operate mainly in winter and exhibit relatively low full load hours, while nuclear plants operate more continuously. While these results are conditional on the study's assumptions, they highlight a trade-off between adequacy requirements and economic utilization for dispatchable capacity.

**Finding 8: The European energy transition and market integration strongly shape Swiss system operation (see Sections 4.10 and 4.11).**
The evolution of the European generation mix has a direct impact on Swiss system operation. Higher renewable penetration in Europe increases the availability of low-cost electricity, leading to more frequent and larger imports. At the same time, the degree of market integration is a key determinant of dispatch patterns. Reduced interconnection capacity limits cross-border exchanges, decreases imports, and shifts the system towards greater reliance on domestic generation and flexibility. These results highlight that adequacy and import dependence cannot be assessed in isolation, but must be evaluated jointly with assumptions on European system evolution and the level of cross-border integration.

**Finding 9: Internal transmission constraints do not fundamentally alter the main conclusions but can moderate system behavior (see Section 4.12).**
The nodal sensitivity analysis suggests that internal grid constraints slightly reduce the magnitude of import–export flows and smooth dispatch patterns, but do not qualitatively change the overall system dynamics. The main roles of hydropower, renewables, and dispatchable technologies remain consistent. This indicates that the core findings of the study are robust to a more detailed representation of the Swiss transmission system.

### 5.2 Next steps

Various directions for further analysis emerge from this study and could strengthen both the robustness and the policy relevance of the results.

**First, a more comprehensive treatment of uncertainty is needed.** Future work should extend the analysis across a broader set of weather years and explicitly include extreme events, such as prolonged low renewable output (so-called “dunkelflaute” periods), as well as dry hydrological conditions. In addition, incorporating forced outages, maintenance schedules, and fuel availability constraints would allow moving from a deterministic assessment to a probabilistic adequacy evaluation.

**Second, a more detailed representation of hydropower systems should be developed.** In particular, modeling hydro cascades, plant-level constraints, and geographically distributed inflows would improve the realism of both seasonal storage and short-term flexibility. This would allow a better assessment of operational limits, coordination constraints, and the true flexibility potential of the Swiss hydro fleet.

**Third, the European system representation and market design assumptions should be refined.** Future analyses could include flow-based market coupling and a more detailed representation of sector coupling, including hydrogen production, storage, and reconversion pathways. This would improve the understanding of cross-border dynamics and price formation.

**Fourth, the role of flexibility resources should be reassessed under more realistic operational conditions.** Introducing uncertainty, unit commitment constraints, and higher spatial resolution would likely increase the estimated value of batteries, demand-side response, and distributed flexibility. In particular, their role in covering critical peak hours, managing congestion, and improving system resilience should be evaluated more explicitly.

Overall, these extensions would allow moving from a stylized, system-level assessment toward a more comprehensive and operationally grounded evaluation of Switzerland’s future electricity system. By integrating uncertainty, market design, detailed asset representation, and network constraints, future analyses can provide a more complete picture of both adequacy and system performance. This, in turn, would support more informed decision-making by linking technical feasibility, economic efficiency, and security of supply in a consistent analytical framework.

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# A Additional assumptions on scenarios

### European countries included in the study

Consistently with the European Reference scenario provided by Axpo, the following countries are included in the model: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, United Kingdom.

### Offshore hubs

The TYNDP assumptions include offshore hubs in the analyzed system. Since offshore hubs are modeled as sector-coupled assets (e.g. with the option to produce hydrogen), they are excluded from the TYNDP scenario in this study.

### Electrolysis

Electrolysis is modeled as a fully flexible demand with a reduced Value of Lost Load (VoLL). The VoLL is assumed to be around 50 CHF/MWh and is computed to reflect the market value of hydrogen produced with 1 MWh of electricity. This is computed starting from the assumed hydrogen market value (144.51 CHF/MWh as shown in Table 3.5.1), an average electrolyzer efficiency of 70%, and an additional cost markup of 50% to account for storage and transportation. Under these assumptions, 1 $\mathrm{MWh_{el}}$ yields 0.7 $\mathrm{MWh_{H_2}}$ and thus about $0.7 \times 144.51 \approx 101$ CHF/$\mathrm{MWh_{el}}$ of hydrogen value. Applying the 50% storage/transport cost reduction results in $\approx 50$ CHF/MWh, consistent with the VoLL used in the model.

The installed electrolyzer capacity in European countries is taken directly from the corresponding dataset (Axpo's reference and TYNDP). For Switzerland, the installed capacity is computed assuming that there are enough electroylzers to cover the demand with a 50% utilization factor across the year.

In this study, electricity demand for electrolyis should not be interpreted as a strict requirement but more as a target. This demand is not accounted for within the load shedding metric.

### Heating and electromobility demand time series

Electromobility demand is represented by a stylized weekly pattern repeated throughout the year (see Figure A.1). Weekdays feature two charging peaks (a pronounced evening spike and a smaller morning increase), while weekend days exhibit only a reduced evening peak.

Heat pump demand follows a daily load shape with a large morning peak and a smaller evening peak (Figure A.2). This daily profile is scaled by an annual seasonality curve (Figure A.3), peaking in mid-winter and reaching its minimum in mid-summer.

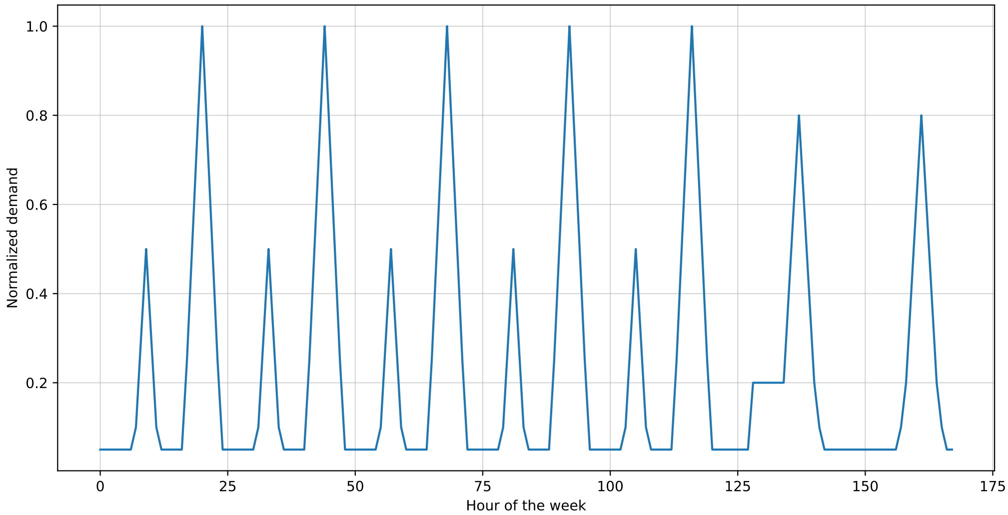


Figure A.1: Normalized electromobility demand during the first week of January (first day is a Monday).

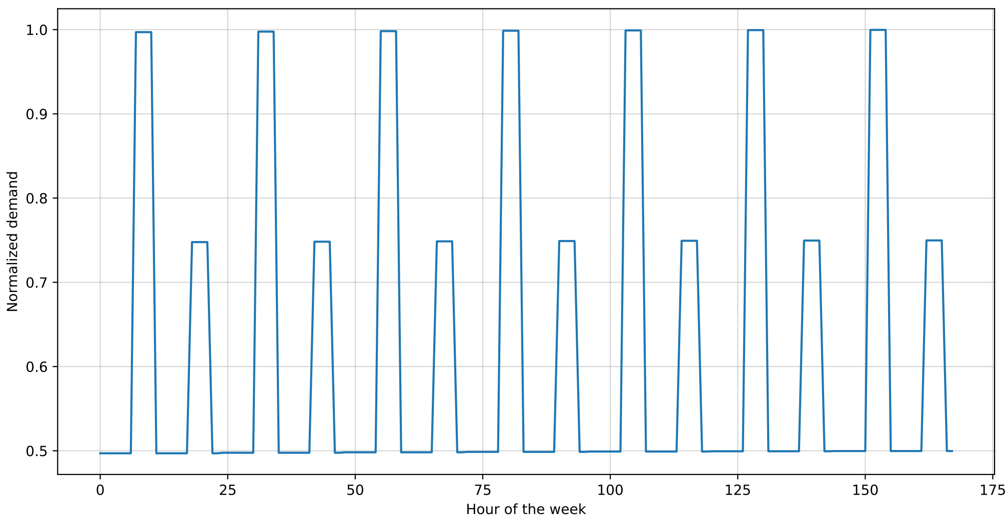


Figure A.2: Normalized heat pump demand during the first week of January (first day is a Monday).

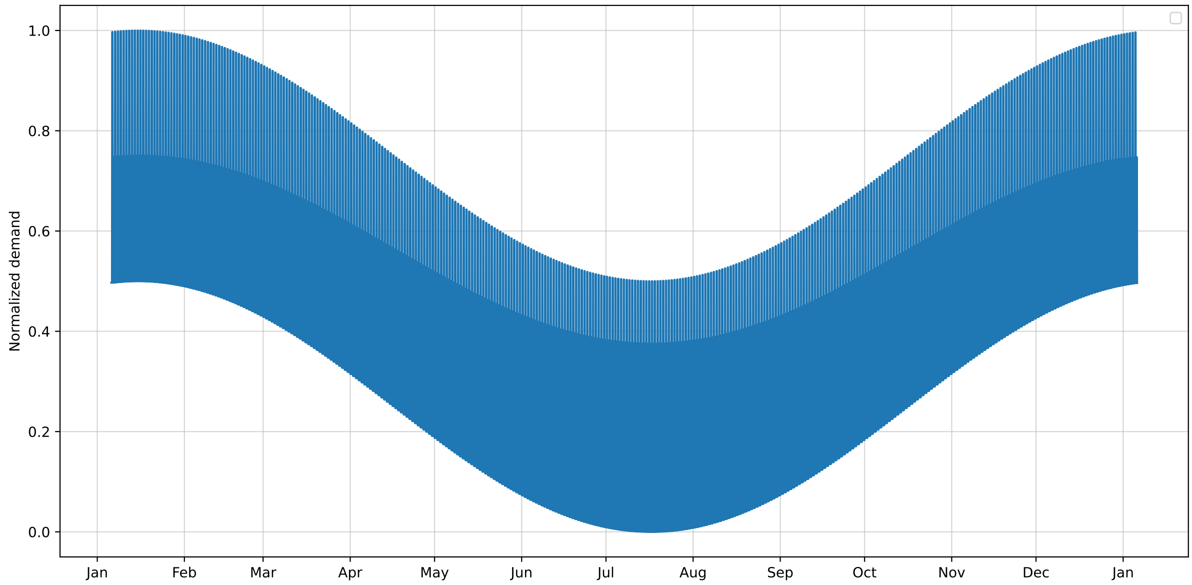


Figure A.3: Normalized heat pump demand, annual profile.