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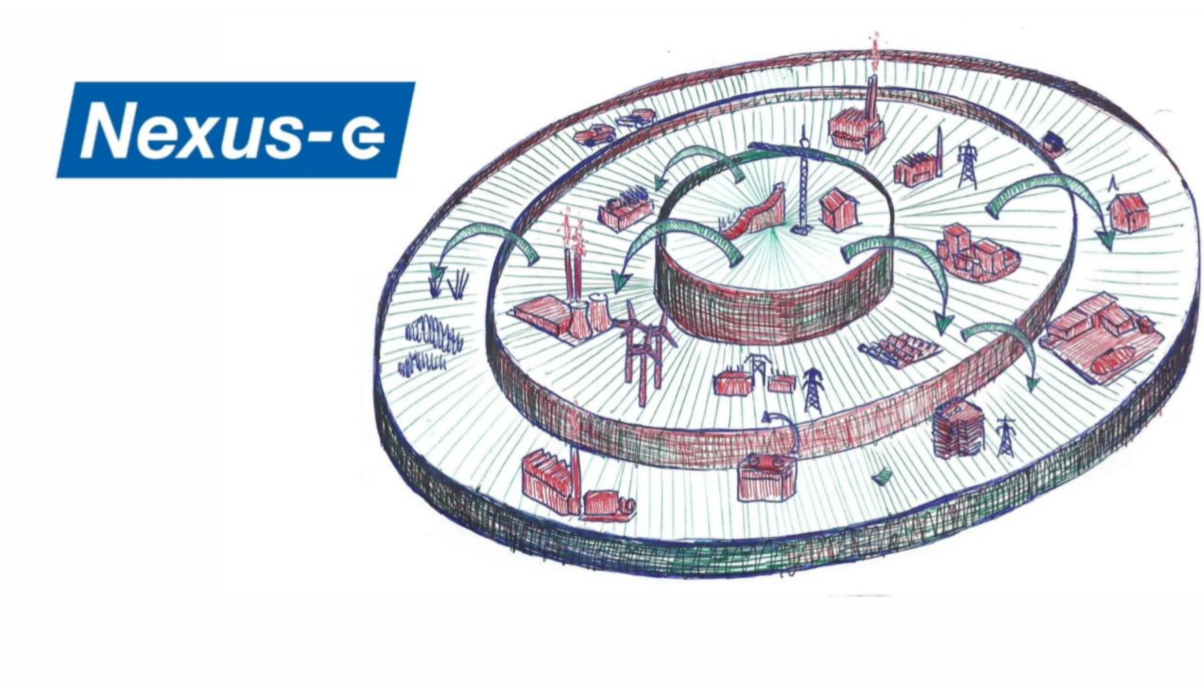
Full Report v2

Swiss electricity supply after the “Mantelerlass” – quo vadis?

A perspective on Nuclear Power



Energy
Science
Center

Date: September 2023

Location: Zurich

Publisher:
ETH Zurich
Energy Science Center
Sonneggstrasse 28, CH-8092, Zürich
www.esc.ethz.ch

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Acknowledgements: This work was commissioned and financed by Economiesuisse.

Zusammenfassung

Im Jahr 2023 berät das Schweizer Parlament über die Revision des Energie- und Stromversorgungsgesetzes. Dieser so genannte "Mantelerlass" kombiniert neue Ziele für den Ausbau der erneuerbaren Energien und Massnahmen zur Erreichung dieser Ziele. Es wird erwartet, dass trotz dieser hohen Ziele für die erneuerbaren Energien die Nettoimporte im Winter aus drei Gründen zunehmen werden: i) die Photovoltaik (PV) auf den Dächern - die Stromerzeugungstechnologie mit der derzeit höchsten jährlichen Installationsrate - produziert nur 20-30 Prozent ihres jährlichen Stroms im Winterhalbjahr, ii) die Elektrifizierung des Wärmesektors erhöht die Nachfrage, insbesondere im Winter, und iii) der geplante Ausstieg aus der Kernenergie, welche heute für fast die Hälfte der Schweizer Stromerzeugung im Winter verantwortlich ist (siehe z.B. Swiss Energy-Charts).

In diesem Projekt untersuchen wir die Rolle der Kernkraftwerke (KKW) in einem Stromsystem mit einem hohen Anteil an erneuerbaren Energien. Insbesondere konzentrieren wir uns auf die Auswirkungen (a) der Lebensdauer bestehender KKW und (b) des Baus neuer KKW auf das Schweizer Stromsystem in Bezug auf die Stromerzeugung, die Systemkosten und die Nettoimporte im Winter. Wir verwenden die Modellierungsplattform Nexus-e, um vier Szenarien zu bewerten, welche die Entwicklung des Schweizer Stromsystems von heute bis 2050 darstellen. Die Betriebsdauer der KKW in der Schweiz ist ungewiss, vor allem weil die derzeitige Politik den Betrieb der bestehenden Anlagen erlaubt, solange diese sich als sicher erweisen. Daher berücksichtigen die Szenarien unterschiedliche Laufzeiten der KKWs: Das Referenzszenario stellt den Status quo der Schweizer KKW Laufzeit dar, d.h. 60 Jahre für Beznau I und II und 50 Jahre für Gösgen und Leibstadt. Im Szenario KKW60 gehen wir davon aus, dass auch die KKW Gösgen und Leibstadt die Genehmigung für eine Betriebsdauer von 60 Jahren erhalten. Im Szenario KKW6580 werden Beznau I und II für 65 Jahre und Leibstadt und Gösgen für 80 Jahre betrieben. Im Szenario KKW60+ gehen wir davon aus, dass zusätzlich zu den 60 Jahren Betriebszeit für alle bestehenden KKW auch ein neues KKW bis 2040 gebaut wird. In Tabelle 1 sind die Betriebszeiten aller Kernkraftwerke in diesen Szenarien dargestellt. Alle weiteren Annahmen und Eingabedaten, die in Nexus-e verwendet werden, sind im "Nexus-e Input and System Data" Report beschrieben

Table 1: Übersicht Laufzeit Schweizer KKWs

KKW	Status	Kapazität [MW]	in Betrieb seit	in Betrieb bis			
				Referenz	KKW60	KKW6580	KKW60+
Mühleberg	ausser Betrieb	390	1972	2019	2019	2019	2019
Beznau I	in Betrieb	380	1969	2029	2029	**2035**	2029
Beznau II	in Betrieb	380	1972	2032	2032	**2037**	2032
Goesgen	in Betrieb	1060	1979	2029	**2039**	**2059**	**2039**
Leibstadt	in Betrieb	1275	1984	2034	**2044**	**2064**	**2044**
Neues KKW	-	1600	2040	-		-	**2100**

Unsere Ergebnisse führen zu den folgenden fünf Hauptschlussfolgerungen:

1. Mit der derzeitigen Politik und den geltenden Vorschriften könnten die Ziele für den Ausbau der erneuerbaren Energien im Mantelerlass schwer zu erreichen sein. Eine Verlängerung der Förderungsdauer, z.B. für die alpine PV, über 2025 hinaus könnte hilfreich sein. Eine Kombination aus einem Mangel an erneuerbaren Energien und einem Ausstieg aus der Kernenergie vor 2050 kann zu höheren Winterimporten im Vergleich zu heute führen.

   In unserem Referenzszenario werden bis 2050 hauptsächlich PV-Dächer (35 GW) und einige alpine PV-Anlagen (1 GW) installiert (siehe Abbildung 1a). Die im Mantelerlass definierten Ziele für erneuerbare Energien werden jedoch im Jahr 2035 deutlich (Referenzszenario: 25 TWh, Ziel: 35 TWh) und im Jahr 2050 leicht verfehlt (Referenzszenario: 43 TWh, Ziel: 45 TWh). In diesem Szenario wird vor allem Dach-PV zugebaut, um die steigende Stromnachfrage und den Ausstieg aus der Kernenergie abzufangen. Da wir nur die aktuellen politischen und regulatorischen Rahmenbedingungen, wie beispielsweise Subventionen, berücksichtigen, erhalten alpine PV Anlagen nur bis 2025 Subventionen. Ohne diese finanzielle Unterstützung bleibt der Zubau von PV in den Alpen bis 2050 auf einem niedrigen Niveau.

Dieses Szenario zeigt ähnliche jährlichen Nettoimporte bis 2050 wie wir sie auch heute sehen. Über das Jahr hinweg importiert die Schweiz ähnlich viel Strom wie sie exportiert. Das bereits heute zu beobachtende saisonale Muster wird sich jedoch bis 2050 noch verstärken. Die Schweiz wird in den Sommermonaten zu einem starken Nettoexporteur, während sie im Winter die verfügbaren Nettoimporte aus den Nachbarländern nutzt (siehe Abbildung 1b). Vor allem in den Jahren nach dem Atomausstieg verzeichnet die Schweiz im Winter die höchsten Nettoimporte. In diesem Szenario steigen die Winter-Nettoimporte im Jahr 2040 auf bis zu 10 TWh, während die Netto-Winterimporte in der Vergangenheit im Durchschnitt bei 5 TWh lagen.

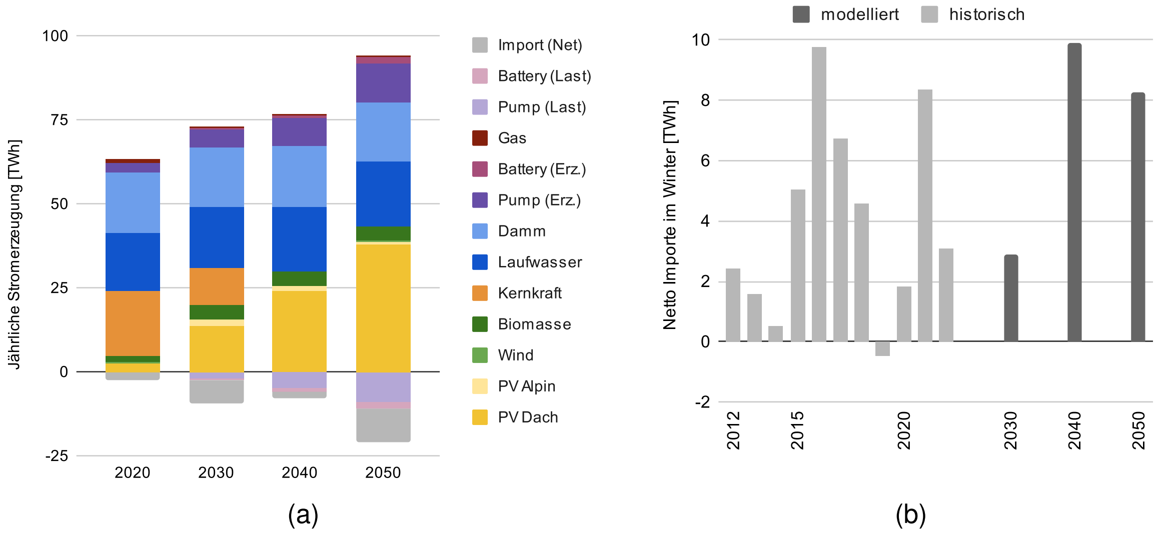


Figure 1: Installierte Erzeugungskapazitäten (1a) und Nettoimporte im Winter im Referenzszenario (1b).

2. Ein längerer Betrieb von KKWs kann Strom im Winter liefern und somit die Importe während dieser Monate reduzieren. Eine solche zusätzliche inländische Stromerzeugung könnte auch die Gesamtkosten der Stromversorgung senken und den Anstieg der Strompreise abmildern.

   In den Szenarien mit verlängerter Laufzeit (KKW60, KKW6580) sind die Nettoimporte im Winter im Vergleich zum Referenzszenario niedriger (siehe Abbildung 2a). Die Verlängerung des Betriebs von Gösgen und Leibstadt um 10 Jahre kann den Anstieg der Nettoimporte in den Jahren 2030 und 2040 abmildern, hat aber keine Auswirkungen im Jahr 2050, da bis dahin alle KKW aus dem Betrieb genommen sind. Mit 80 Betriebsjahren für die KKW Gösgen und Leibstadt und 65 Betriebsjahren für Beznau I und II hätte die Schweiz im Modell auch noch in 2050 einen ausgeglichenen Stromhandel im Winter mit ihren Nachbarländern. Die höhere inländische Stromproduktion senkt auch generell die Gesamtkosten der Stromversorgung in unseren Szenarien (siehe Abbildung 2b). Während im Referenzszenario die Deckung des Schweizer Strombedarfs bis 2050 zu kumulierten Kosten von 109,5 Mrd. CHF führt, reduzieren sich diese Kosten im KKW60-Szenario um 3 Mrd. CHF und im KKW6580-Szenario um 11 Mrd. CHF[1]. Basierend auf historischen Daten gehen wir davon aus, dass die durchschnittlichen Kosten für die Verlängerung des Betriebs eines Reaktors um 10 Jahre 1 Mrd. CHF betragen (siehe Box). Wir haben in unseren Szenarien auch

[1] Die in dieser Studie genannten Kosten inkludieren nicht die potenziellen Kosten für den Netzausbau.

beobachtet, dass ein längerer Betrieb der KKW den Anstieg der Strompreise über die simulierten Jahre abschwächt (siehe Abbildung 2c). So reduziert das Szenario KKW6580 die durchschnittlichen jährlichen Strommarktpreise um 9 CHF/MWh von 90 CHF/MWh auf 81 CHF/MWh. Der Grund für die niedrigeren Preise liegt vor allem darin, dass der Einsatz von teureren Reserve- und Spitzenlastkraftwerken vermieden werden kann.

Box: Kosten KKWs

Die Verlängerung der Betriebszeit erfordert in der Regel eine Modernisierung und sicherheitstechnische Nachrüstung der Kernreaktoren. Seit der Inbetriebnahme von Beznau 1 und 2 mussten mehr als 2,5 Milliarden Franken in die Sicherheit und Zuverlässigkeit der beiden Anlagen investiert werden.[a] Ein weiteres Beispiel ist das KKW Leibstadt, bei dem Axpo seit 2010 eine Milliarde Franken in die Sicherheit, aber auch in die Leistungssteigerung investiert hat.

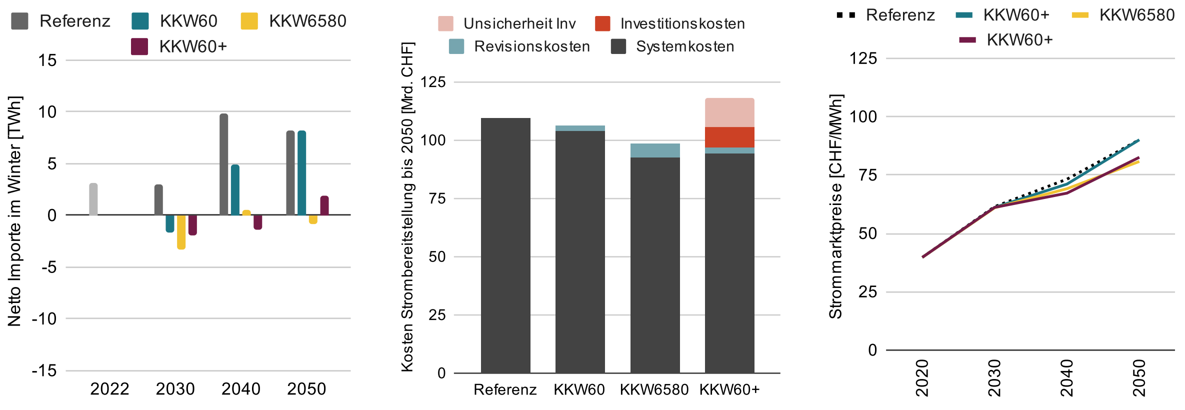
Derzeit sind in Mitteleuropa drei neue KKW im Bau, deren geschätzte Kosten zwischen 7'600 und 12'600 CHF pro KW liegen.[b] Alle Anlagen überschreiten bereits das ursprünglich geplante Budget. Ausserhalb Europas sind die Baukosten deutlich niedriger, z.B. CHF 2'000 pro kWp in Korea und CHF 3'200 pro kWp in China. Was die Bauzeit betrifft, so dauern die Projekte in Europa durchschnittlich 7,5 Jahre und damit deutlich länger als im weltweiten Durchschnitt. Im April 2023 nahm das finnische KKW Olkiluoto 3, das erste KKW in Europa seit 16 Jahren, nach 18 Jahren Bauzeit den Regelbetrieb auf.[c] Andere europäische KKWs sind seit 16 Jahren (Frankreich) bzw. 5 Jahren (Grossbritannien) im Bau. Die extrem langen Bauzeiten sind zum Teil darauf zurückzuführen, dass es sich um "first-of-its-kind" Anlagen handelt und während der Covid19-Pandemie Probleme in der Lieferkette auftraten. Für die Schweiz ist zu erwarten, dass neue KKW in Bezug auf Baukosten und -zeit den europäischen Beispielen folgen werden.

[a] Nuklearforum Schweiz. 2022. "Investitionen in Den Langzeitbetrieb Prägen Die Stromproduktion 2021." 2022. https://www.nuklearforum.ch/de/news/investitionen-den-langzeitbetrieb-praegen-die-stromproduktion-2021.

[b] Rothwell, Geoffrey. 2022. "Projected Electricity Costs in International Nuclear Power Markets." Energy Policy 164. https://doi.org/10.1016/J.ENPOL.2022.112905

[c] Lehto, Essi. 2023. "After 18 Years, Europe's Largest Nuclear Reactor Starts Regular Output." Reuters. 2023. https://www.reuters.com/world/europe/after-18-years-europes-largest-nuclear-reactor-start-regular-output-sunday-2023-04-15/.

Durch den Bau eines neuen KKW mit einer Leistung von 1,6 GW (KKW60+) werden die Nettoimporte im Winter und die Strompreise im Vergleich zum Szenario KKW60 weiter gesenkt. Die Stromversorgungskosten hängen jedoch stark von den angenommenen Investitionskosten ab. Mit den aktuellen Investitionskosten für KKW in Europa (siehe Box) führt das KKW60+-Szenario zu wesentlich höheren Kosten im Vergleich zu dem Szenario ohne neues KKW (KKW60). Nur wenn die Investitionskosten rund 5 Mrd. CHF pro GWp unterschreiten, wird der Bau eines neuen KKW die Schweizer Stromversorgungskosten zu senken. Unsere Szenarien zeigen auch, dass das NPP60+-Szenario selbst bei den niedrigen Investitionskosten, die wir ausserhalb Europas beobachten (z.B. 3,2 Mrd. CHF in China), höhere Stromversorgungskosten aufweist als das NPP6580-Szenario. Es muss beachtet werden, dass die Szenarien das Stromsystem nur bis 2050 darstellt und daher die wirtschaftlichen Vor- und Nachteile der Stromerzeugung nach 2050 nicht vollständig darstellen kann.



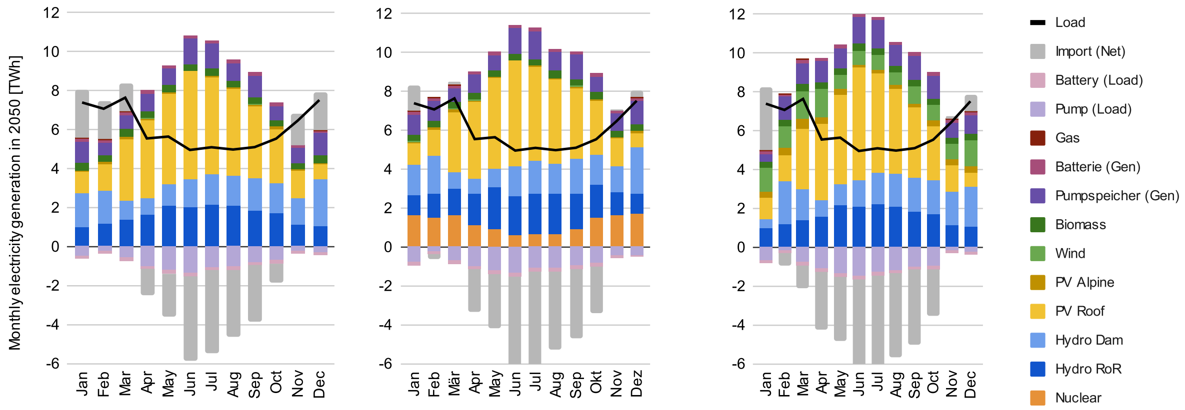
(a) (b) (c)

Figure 2: Vergleich des Referenzszenarios, des KKW60-Szenarios und des KKW6580-Szenarios in Bezug auf die Nettoimporte im Winter (2a), die Gesamtkosten der Stromversorgung (2b) und die Strommarktpreise (2c).

3. Erneuerbare Freiflächenanlagen mit hohen Anteilen an der Winterstromerzeugung, wie beispielsweise die alpine PV und die Windkraft, sind eine weitere Möglichkeit, die Stromimporte im Winter zu reduzieren. Alpine PV Anlagen produzieren bis zu 55 Prozent ihres Stroms im Winter (Oktober bis März), die Windkraft mit rund 60 Prozent sogar noch mehr. Generell gilt: Je früher der Ausstieg aus der Kernenergie erfolgt, desto schneller muss die Kapazität der Erneuerbaren ausgebaut werden, um die Nettoimporte im Winter niedrig zu halten.

   Abbildung 3 vergleicht die monatliche Stromerzeugung in 2050 des Referenzszeanrios (Abbildung 3a) mit dem KKW6580-Szenario (Abbildung 3b) und einem Szenario mit ausgeglichenen Nettoimporten im Winter und einem Ausstieg aus der Kernenergie vor 2050 (Abbildung 3c). In Letzterem werden zusätzlich 3 GW an alpiner PV und 8 GW an Windkraft installiert. Insgesamt produzieren die erneuerbaren Energien im Jahr 2050 mehr als 55 TWh und benötigen zusätzliche Investitionen von 19 Mrd. CHF.

   In diesem Projekt haben wir andere Optionen zur Verringerung der Nettoimporte im Winter, wie z.B. die inländische Produktion oder den Import synthetischer Brennstoffe, nicht im Detail bewertet. Ob die Schweiz solche synthetischen Brennstoffe für das Stromversorgungssystem nutzen wird, hängt stark von der Entwicklung der Wasserstoffimportpreise ab, die im Moment sehr unsicher ist. Die inländische Produktion von Wasserstoff im Sommer und anschliessender Speicher des Gases bis zum Winter ist problematisch, da es aktuell keine grosstechnische Speichermöglichkeit gibt.



(a) (b) (c)

Figure 3: Monatliche Stromerzeugung im Jahr 2050 für das Referenzszenario (3a) und Szenarien mit langem KKW-Betrieb (KKW6580) (3b) und starkem Ausbau der erneuerbaren Energien (3c).

4. Der Betrieb von KKWs wird sich in einem zukünftigen Schweizer Elektrizitätssystem, das stark auf Wasserkraft und Sonnenenergie basiert, wahrscheinlich ändern. Heute laufen die Schweizer KKWs in der Regel die meiste Zeit mit Nennleistung und werden während des Brennelementwechsels und ungeplanter Revisionen abgeschaltet. In Zukunft könnten sie jedoch vermehrt im Winter und in Zeiten geringer erneuerbarer Erzeugung betrieben werden. Ein solcher Betrieb könnte sich für neue KKW mit schnellen Rampengeschwindigkeiten besser eignen, d.h. Herunterfahren auf null Leistung ("Hot Shutdown") und Hochfahren auf die volle Leistung innerhalb weniger Stunden. Die Abschaltung von KKWs für eine längere Dauer von Tagen bis hin zu mehreren Monaten ("Cold Shutdown") könnte ebenfalls geeignet sein, insbesondere in Situationen mit begrenzten Exportmöglichkeiten im Sommer für die Schweiz.

   Abbildung 4a zeigt den stündlichen Einsatz der Kernenergie in der Schweiz im Jahr 2022. Während im Juni und Juli die Stromerzeugung aus Kernenergie hauptsächlich wegen geplanter Wartungsarbeiten und Brennelementwechsel zurückgeht, arbeiten die KKW in fast allen anderen Stunden mit maximaler Kapazität. Abbildung 4b zeigt stattdessen den Betrieb des neuen KKW im Jahr 2050 im Szenario KKW60+, mit einer maximalen Kapazität von 1,6 GW. Der geplante Stillstand ist hier für den August berücksichtigt. Aber auch in vielen anderen Stunden variiert die Stromerzeugung des KKW's um den Marktpreissignalen zu folgen.

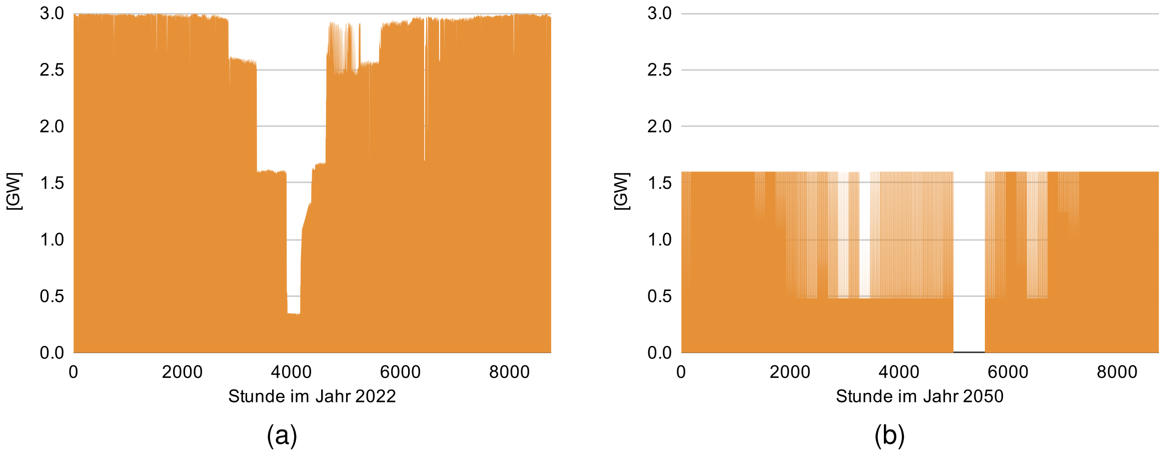


Figure 4: Stündliche Stromerzeugung durch Kernkraftwerke (4a) in 2022 (historische Daten) und (4b) im Jahr 2050 für das Szenario KKW60+.

5. Im Allgemeinen ist der Wert der KKW bei allen Sensitivitäten ähnlich. Für alle Basisszenarien testen wir drei Sensitivitäten. Wir bewerten die Auswirkungen unterschiedlicher Entwicklungen in den Nachbarländern, von Stromhandelsbeschränkungen (unter Berücksichtigung der möglichen Auswirkungen neuer EU-Vorgaben) und einer höheren Stromnachfrage aufgrund der heimischen Wasserstoffproduktion.

Es muss beachtet werden, dass sich die Szenarien ausschliesslich auf die technisch-wirtschaftliche Darstellung von Kernkraftwerken beziehen. Andere Aspekte wie das Risiko nuklearer Katastrophen, die Endlagerung nuklearer Abfälle, die Abhängigkeit von Uranimporten oder die Unwägbarkeiten bei den Baukosten und der Dauer der Planung und des Baus eines neuen Kraftwerks werden nicht berücksichtigt. Auch die Ergebnisse dieser Studie sollen einen quantitativen Einblick in die Unterschiede der Szenarien geben, dienen aber nicht als Prognosen. Die Modellierung des Schweizer Stromsystems unterliegt vielen Annahmen und Vereinfachungen. In den Gesamtkosten der Szenarien sind die Kosten für den notwendigen Ausbau des Übertragungs- und Verteilnetzes nicht enthalten. Die Ergebnisse für alle Szenarien sind auf dem Nexus-e Webviewer unter der folgenden Webadresse einsehbar: nexus-e.org/role-of-nuclear-power. Die verschiedenen Szenarien können aus einem Dropdown-Menü ausgewählt und miteinander verglichen werden.

Summary

In 2023, the Swiss parliament is discussing the revision of the Energy and Power Supply Act. This so-called "Mantelerlass" combines new targets for the expansion of renewable energies and measures to achieve this target. It is expected that despite these high targets for renewables, net imports in winter will increase due to three reasons: i) rooftop photovoltaics (PV) – the electricity generation technology that currently has the highest annual installation rate – produces only 20-30 percent of their annual electricity during the winter half-year, ii) electrifying the heating sector increases demand, especially in winter, and iii) the planned phase-out of nuclear power, which is today responsible for almost half of the Swiss electricity generation in winter (see e.g. Swiss Energy-Charts).

In this project, we assess the role of nuclear power plants (NPPs) in an electricity system with high shares of renewables. In particular, we focus on the impact of (a) the lifetime of existing NPPs and (b) the construction of new NPPs on the Swiss electricity system regarding electricity generation, system costs, and winter net imports. We use the Nexus-e modeling platform to assess four baseline scenarios that represent developments of the Swiss electricity system from today to 2050." There is uncertainty in the operational life of NPPs in Switzerland, mainly because the current policy allows the existing plants to continue operating while proven safe. Therefore, we develop the scenarios such that a range of operating years are considered: the reference scenario represents the status quo of Swiss NPP lifetime, meaning 60 years for Beznau I and II, and 50 years for Goesgen and Leibstadt. In the NPP60 scenario, we assume that the NPPs Goesgen and Leibstadt get the approval to operate for 60 years. In the NPP6580 scenario, Beznau I and II operate for 65 years and Leibstadt and Goesgen for 80 years. In the NPP60+ scenario, we assume that on top of 60 years operating time for all existing NPPs also a new NPP is constructed in 2040. Table 2 depicts the operating time of all nuclear plants in these scenarios. All additional assumptions and input data used in Nexus-e are described in the “Nexus-e Input Data and System Setup” report[2].

Table 2: Overview of operation time Swiss NPPs

Reactor Unit	Status	Capacity [MW]	Commercial Operation since	Expected operation until			
				Reference	NPP60	NPP6580	NPP60+
Mühleberg	decommissioned	390	1972	2019	2019	2019	2019
Beznau I	In operation	380	1969	2029	2029	**2035**	2029
Beznau II	In operation	380	1972	2032	2032	**2037**	2032
Goesgen	In operation	1060	1979	2029	**2039**	**2059**	**2039**
Leibstadt	In operation	1275	1984	2034	**2044**	**2064**	**2044**
New NPP	-	1600	2040	-		-	**2100**

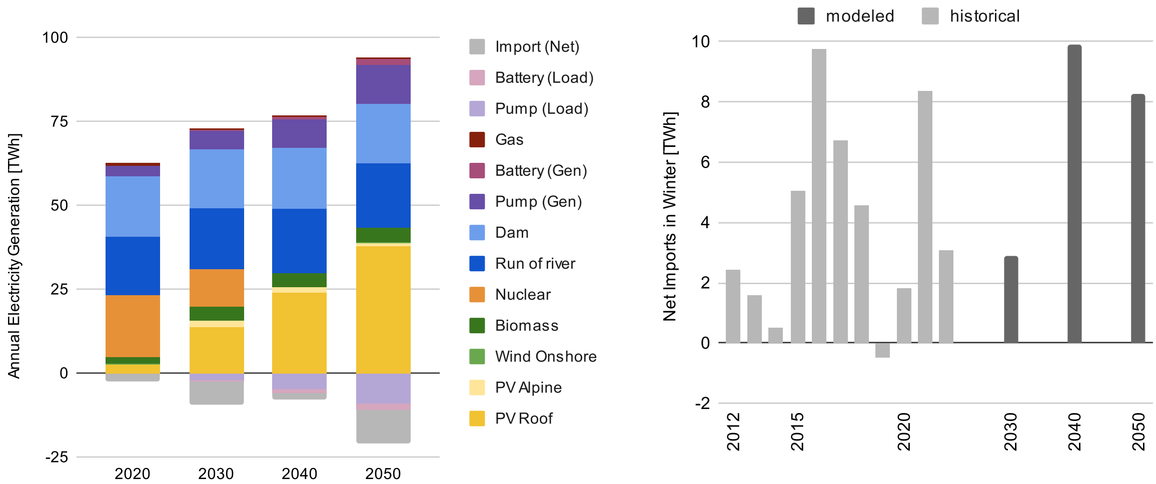
Our results provide the following five main conclusions:

1. With current policies and regulations, the targets for the expansion of Renewables in the "Mantelerlass" might be challenging to achieve. Extending the duration of subsidies, for example, for alpine PV beyond 2025, could be helpful. A combination of both a lack of Renewable installations and a phase-out of nuclear power before 2050 can lead to higher winter imports compared to today.

   In our reference scenario, mainly rooftop PV (35 GW) and some alpine PV (1 GW) are being installed until 2050 (see Figure 5a). However, the targets for Renewables defined in the "Mantelerlass" are missed by a large margin in 2035 (reference scenario: 25 TWh, target: 35 TWh) and slightly in 2050 (reference scenario: 43 TWh, target: 45 TWh). In this scenario, rooftop PV is mainly responsible for covering the increasing demand and the phase-out of nuclear power. As we only consider current regulations and policies in place, alpine PV receives subsidies only until 2025. Without such financial support, alpine PV installations remain at a low level until 2050.

[2] Input Data and System Setup, 2022, https://nexus-e.org/documentation/

In this scenario, annual net imports remain at a similar level as today. Over a year, Switzerland imports a similar amount of electricity as it exports. However, the seasonal pattern that can be observed already today, is intensified by 2050. Switzerland becomes a strong net exporter in the summer months whereas in winter it utilizes available net imports from the neighboring countries (see Figure 5b). Especially in the years after the nuclear phase-out, Switzerland sees the highest net imports in winter. In this scenario the winter net imports in 2040 increase up to 10 TWh, whereas historically net winter imports were on average 5 TWh.



(a) (b)

Figure 5: Installed generation capacities (5a) and winter net imports in the reference scenario (5b).

2. A longer operation of NPPs can provide electricity in winter and therefore reduce imports during these months. Such additional domestic electricity generation might also reduce the total costs of electricity supply and mitigate the increase in electricity prices.

   In the scenarios with extended lifetime (i.e., NPP60, NPP6580), winter net imports are lower compared to the reference scenario (see Figure 6a). Extending the operation of Goesgen and Leibstadt by 10 years can mitigate the increase in net imports in 2030 and 2040 but has no impact in 2050 as, by then, all NPPs are phased out. With 80 years of operation for the NPPs Goesgen and Leibstadt and 65 years of operation for Beznau I and II, Switzerland has a balanced electricity trade in winter with its neighboring countries even in 2050. The higher domestic electricity generation also generally reduces the total cost of electricity supply in our scenarios (see Figure 6b). Whereas in the reference scenario providing enough electricity to cover the Swiss electricity demand results in cumulative costs of 109.5 bn CHF by 2050, these costs are reduced by 3.5 bn CHF in the NPP60 scenario and by 10 bn CHF in the NPP6580 scenario, respectively.[3] Based on historical data, we assume that the average cost of extending a reactor's operation by 10 years is CHF 1 billion. We also observed in our scenarios that longer operation of NPPs also mitigates the increase in electricity prices over the simulated years (see Figure 6c). For example, the NPP6580 scenario reduces the annual average electricity market prices by 9 CHF/MWh from 90 CHF/MWh to 81 CHF/MWh. The reason for the lower prices is mainly that the dispatch of more expensive backup and flexible capacities can be avoided.

[3]The mentioned costs in this study do not reflect the potential cost for grid extensions

Box: NPP costs

Extending the operating time typically requires modernization and safety upgrades of nuclear reactors. Since the time when Beznau-1 and -2 were commissioned, more than CHF 2.5 billion have had to be invested in the safety and reliability of the two plants [a]. Another example is the Leibstadt NPP, for which Axpo has invested CHF 1 billion since 2010 in safety but also performance improvement.

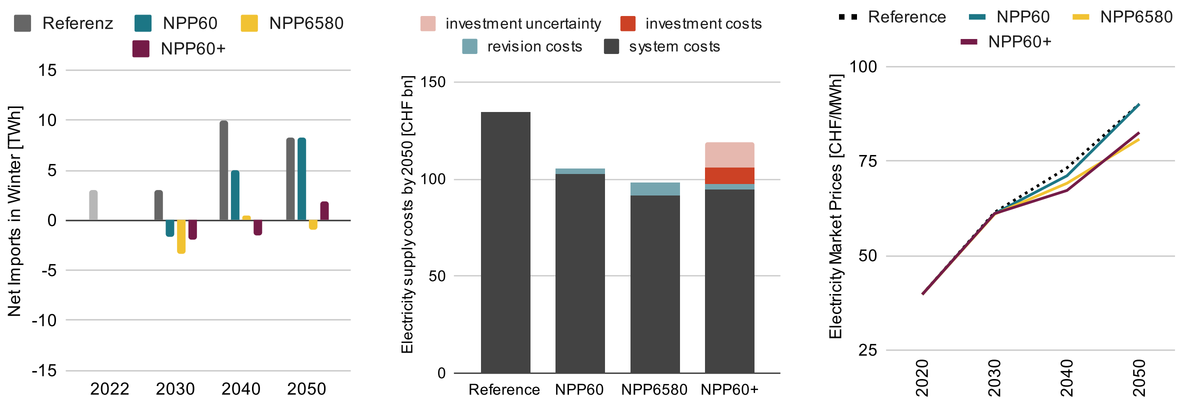
Currently, there are three new NPPs are under construction in Central Europe, with estimated costs ranging from CHF 7'600 to 12'600 per kWp[b]. All plants are already exceeding the originally planned budget. Outside Europe, construction costs are much lower, e.g., CHF 2'000 per kWp in Korea and CHF 3'200 per kWp in China. In terms of construction time, projects in Europe take 7.5 years, significantly longer than the global average. In April 2023, Finland's Olkiluoto 3, the first NPP in Europe in 16 years, began regular operation after 18 years of construction [c]. Other European NPPs have been under construction for 16 years (France) and 5 years (UK). The extremely long construction times are partly due to the fact that they were "first-of-their-kind" plants and supply chain problems occurred during the Covid19 pandemic. For Switzerland, new NPPs can be expected to follow European examples in terms of construction costs and time.

[a] Nuklearforum Schweiz. 2022. “Investitionen in Den Langzeitbetrieb Prägen Die Stromproduktion 2021.” 2022. https://www.nuklearforum.ch/de/news/investitionen-den-langzeitbetrieb-praegen-die-stromproduktion-2021.

[b] Rothwell, Geoffrey. 2022. “Projected Electricity Costs in International Nuclear Power Markets.” Energy Policy 164. https://doi.org/10.1016/J.ENPOL.2022.112905

[c] Lehto, Essi. 2023. “After 18 Years, Europe's Largest Nuclear Reactor Starts Regular Output.” Reuters. 2023. https://www.reuters.com/world/europe/after-18-years-europes-largest-nuclear-reactor-start-regular-output-sunday-2023-04-15/.

Constructing a new NPP with the size of 1.6 GW (NPP60+ scenario) reduces winter net imports and electricity prices further, compared to the NPP60 scenario. Total electricity supply costs are, however, strongly dependent on the assumed investment costs. With investment costs of NPPs in Europe that are currently under construction or have been recently completed (see Box on NPP costs), the NPP60+ scenario results in substantially higher costs compared to the scenario without a new nuclear power plant (i.e., NPP60). Only if investment costs of below CHF 5 bn per GWp can be achieved, constructing a new NPP starts to bring down Swiss electricity supply costs. Our scenarios also show that the NPP60+ scenario shows even in case of extremely low investment costs that we observe outside Europe (e.g., CHF 3.2 billion CHF in China) higher costs of electricity supply compared to the NPP6580 scenario. Please note that the analysis only models the electricity system until 2050 and therefore cannot fully represent the economic advantages and drawbacks of electricity generation beyond 2050.



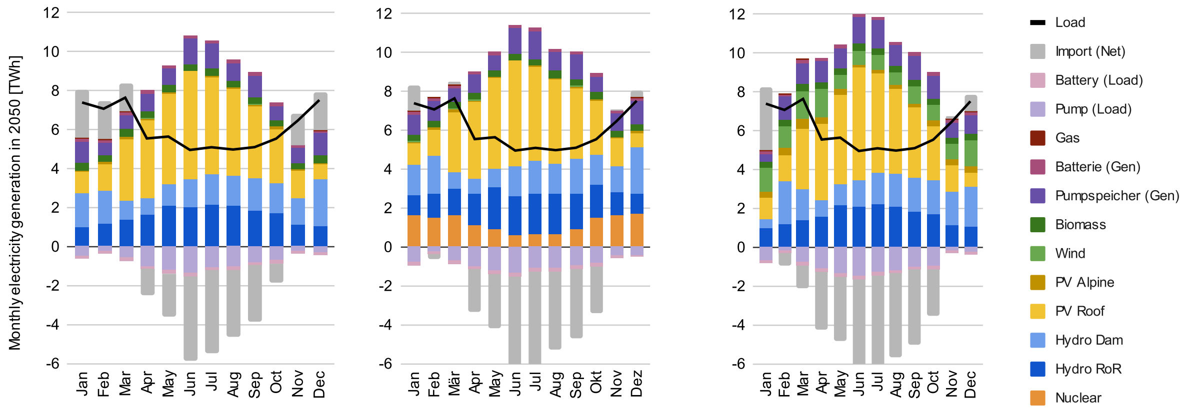
(a) (b) (c)

Figure 6: Comparison of the reference, NPP60, NPP6580, and NPP60+ scenarios in terms of net imports during winter (6a), total electricity supply costs (6b), and electricity market prices (6c).

3. Open-field renewables with high shares of winter electricity generation such as alpine PV and wind power are another option to reduce electricity imports during winter. Alpine PV produces up to 55 percent of its electricity in winter (October to March), and wind power even more at around 60 percent. Generally, we see that the earlier nuclear power is phased out, the faster renewable capacity has to be expanded to keep winter net imports at low values.

   Figure 7 compares these two options and their monthly electricity generation in 2050. Figure 7a depicts the reference scenario and compares it with the NPP6580 scenario (Figure 7b) and a scenario with balanced winter net imports and a nuclear phase-out before 2050 (Figure 7c). In the latter, we see additional installations of 3 GW of alpine PV and 8 GW of wind power. In total, renewables produce more than 55 TWh in 2050, requiring additional investments of CHF 19 billion.

   In this project, we have not assessed in detail other options to reduce net electricity imports in winter such as the domestic production or import of synthetic fuels. Whether Switzerland will utilize such synthetic fuels for the electricity supply system depends heavily on the development of their prices, which is very uncertain at the moment. To domestically produce synthetic fuels in summer and store the gas until winter is challenging as no large-scale gas storage option is yet available.

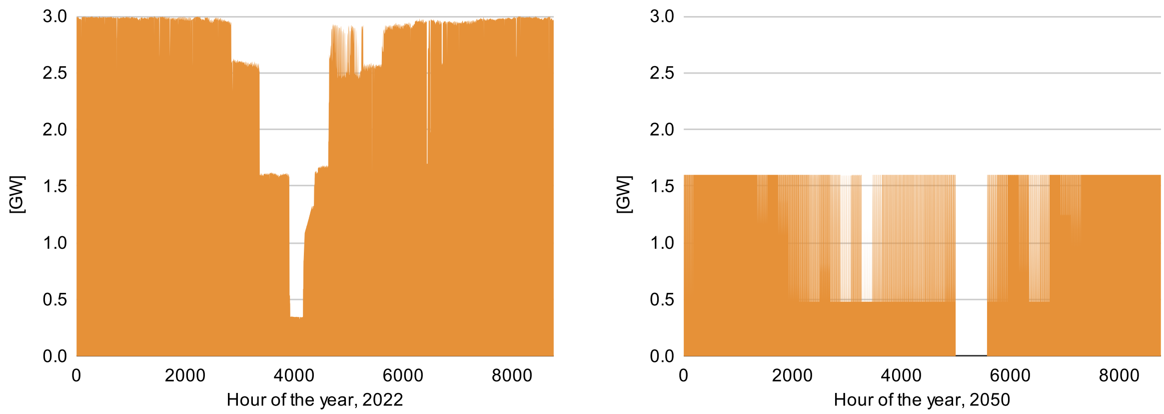


(a) (b) (c)

Figure 7: Monthly electricity generation in 2050 for the reference scenario (7a) and scenarios with long NPP operation (i.e., NPP6580) (7b) and strong renewable expansion (7c).

4. The operation of NPPs likely changes in a future Swiss electricity system that is strongly based on hydropower and intermittent renewables such as wind and solar power. Today, Swiss NPPs typically run most of the time at rated power and are shut down during refueling and unplanned outages. However, in the future, they might operate more in winter and during times of low renewable generation. Such operation might be more suitable for new NPPs with fast ramp rates, i.e., ramp down to zero power (hot shutdown) and ramp up to full power within a few hours. Shutting down NPPs for a longer duration from days to even multiple months (i.e., cold shutdown) might also be suitable especially in situations with limited export capabilities in summer for Switzerland.

   Figure 8a depicts the hourly dispatch of nuclear power in Switzerland in 2022. While in June and July, nuclear generation decreased mainly due to planned maintenance and refueling, in almost all other hours NPPs operate at max capacity. Figure 8b instead depicts the operation of the new NPP in 2050 in the NPP60+ scenario, with a max capacity of 1.6 GW. The planned outage is considered for August. But also in many other hours, the output of the NPP ramps down and up and thereby follows market price signals.



(a) (b)

Figure 8: Hourly electricity generation by nuclear power plants (8a) historically and (8b) in 2050 for the NPP60+ scenario.

5. Generally, we see a similar value of NPPs across all sensitivities. For all basic scenarios, we test three sensitivities. We evaluate the impact of different developments in neighboring countries, of electricity trade restrictions (considering the potential impact of the EU clean energy package), and of higher electricity demand due to domestic hydrogen production.

Please note that the scenarios refer purely to the techno-economic representation of nuclear power plants. Other aspects such as the risk of nuclear catastrophes, the final disposal of nuclear waste, the dependence on uranium imports, or the uncertainties in construction costs and duration of planning and building a new power plant are not considered. Also, the results of this study are intended to provide quantitative insight into the scenario differences but do not serve as forecasts. The modeling of the Swiss electricity system is subject to many assumptions and simplifications. The total costs of the scenarios do not include the costs of the required expansion of the transmission and distribution grid. Results for all scenarios are visible on the Nexus-e Webviewer at the following web address: nexus-e.org/role-of-nuclear-power. The different scenarios can be selected from a drop-down menu and compared to each other.

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1 Introduction

In 2023, the Swiss parliament is discussing the revision of the Energy and Power Supply Act. This so-called “Mantelerlass” aims to improve the framework conditions for the domestic expansion of electricity production from renewable energies and the security of electricity supply in Switzerland. The decree also includes new and ambitious targets for the expansion of renewable energies in Switzerland: 35 TWh annual production from “new renewables” (excluding hydropower) by 2035 and 45 TWh by 2050.

At the same time, however, It is expected that despite these high targets for renewables, winter net imports will likely increase by 2050 mainly due to three reasons: i) In most regions across Switzerland, rooftop photovoltaics (PV) systems – the electricity generation technology that currently has the highest annual installation rate – have only 20-30 percent of their annual electricity production during the winter months, ii) electrifying the heating sector increases demand, especially in winter, and iii) the phase-out of nuclear power, which, today, is responsible for almost half of the Swiss electricity generation in winter (see e.g. Swiss Energy-Charts).

In this project, we assess whether nuclear power plants (NPPs) are a suitable option to address the challenge in such a system with high renewables. In particular, we focus on the following questions:

1. How does the operating time of existing NPPs affect the Swiss electricity system in terms of electricity generation, electricity supply costs, and winter imports?
2. How would a new NPP affect the Swiss electricity system with high shares of renewables?
3. How does the role of nuclear power change when varying our assumptions on developments in neighboring countries or in electricity trading agreements?
4. How does the role of nuclear power change when varying our assumptions on domestic hydrogen production?

To answer the relevant questions, we use the Nexus-e modeling platform.

The remainder of this report is structured as follows: First, we provide a brief background of the history of nuclear power in Switzerland (section 2). We then outline the method and data (section 3) with a focus on how we represent nuclear power in the scenarios. Finally, we present the results (section 4). All scenario results are also presented in our interactive webviewer on www.nexus-e.org.

2 Background

Until the late 1960s, Switzerland generated electricity exclusively from hydropower, but it was evident that Swiss electricity demand was likely to exceed the potential of hydropower. Switzerland did not choose fossil fuels mainly because, first, they were not available as a natural resource in Switzerland, and, second, environmental groups and others strongly opposed them, arguing that clean electricity generation should not be compromised. As a response, the Swiss government encouraged the power utilities to plan for the relatively new nuclear energy technology to cover the increasing electricity demand. To provide legislation for nuclear programs at the federal level, in 1957, Swiss population voted for a new article in the Swiss Constitution. Consequently, the Atomic Energy Act came into force in 1959.[4]

Following the legal development, a series of projects for NPPs were initiated, resulting in a total of five units, which were commissioned between 1969 and 1984: Beznau (including Beznau I and II), Gösgen, Leibstadt, and Mühleberg. The country's first commercial unit was Beznau I, a pressurized water reactor (PWR) ordered by Nordostschweizerische Kraftwerke AG and soon duplicated as Beznau 2, followed by the Mühleberg NPP, a boiling water reactor (BWR) ordered by BKW. Following these three units, a consortium of utilities ordered a large PWR for Gösgen, and the same year, another consortium ordered a similar-sized BWR for Leibstadt.

In 1986, anti-nuclear opposition arose due to the Chornobyl accident and resulted in the abandonment of two additional planned Swiss NPPs in Kaiseraugst and Graben. In 1990, a ten-year moratorium on new Swiss NPP construction was supported by 54.6 percent of the population in a national referendum.

Ten years later, the perception of the Swiss population seemed to change again. In 2003, Swiss voters rejected the two anti-nuclear proposals. With the ten-year moratorium not being prolonged and other anti-nuclear proposals being rejected, legislative and industry activity rose again. In 2005, Switzerland enacted a new Nuclear Energy Act to replace the Atomic Energy Act of 1959. In 2006, ATEL (today Alpiq) was looking for partners to build a nuclear power plant. Also Axpo had been studying sites for a new nuclear power plant. In 2010, the Federal Nuclear Safety Inspectorate (ENSI) stated that the Niederamt, Beznau, and Mühleberg sites were suitable for building new reactors.

Then, in March 2011, the Fukushima nuclear accident happened. As a response, the Federal Council and the Swiss parliament decided to phase out nuclear energy by prohibiting the building of new plants, while the existing plants were to continue operating for as long as they could safely do so. The government had to produce a new energy policy without nuclear power and suggested in 2014 the Energy Strategy 2050. In 2016, the Green Party brought up a referendum, deciding whether nuclear plants should be shut down after a maximum of 45 years of operating lifetime. This referendum was rejected by about 54 percent of the votes.

In May 2017, the Energy Strategy 2050 was approved in a referendum by a 58 percent majority. It includes a gradual withdrawal from nuclear power and a greater reliance on hydro and other renewables. Under this Energy Strategy, no construction licenses are issued for new nuclear power reactors. The country's existing reactors are allowed to remain in operation as long as ENSI considers them safe.

ENSI assesses the safety of NPPs in three ways: First, annual assessments of operating safety are based on event assessments, data from inspections, and safety indicators. Second, similar to all countries under the guidelines of the International Atomic Energy Agency (IAEA), a periodic safety review (PSR) is conducted at least every ten years and is based on the operating experience since the

[4] see more information on https://world-nuclear.org/information-library/country-profiles/countries-o-s/switzerland.aspx

last review[5]. Within the PSR, safety-relevant plant modifications have to be identified and implemented as appropriate. As part of the periodic safety review, if the NPP has been in commercial operation for more than 40 years, an assessment of the long-term operation (LTO) has to be included. Here, the operator has to prove that the plant will run safely during the planned period of operating and whether technical or organizational improvements are planned. Third, in case events of INES 2[6] or higher have occurred in a national or international NPP, further reviews and assessments of the design basis are mandatory. The NPP Beznau provided the latest LTO in 2018 and received feedback from ENSI in 2021, concluding that both reactors fulfill all conditions to run safely for the next ten years. Therefore, the NPP Beznau is expected to run for at least an operational lifetime of 60 years. NPP Goesgen submitted the LTO in 2018, and ENSI is expecting to complete its review by the end of 2023. NPP Leibstadt submitted the LTO at the end of 2022 and will receive feedback in 2025[7].

In 2019, one of the five units, Mühleberg NPP, was permanently shut down. While a 10-year license was granted in 2009, three years later, also as a response to Fukushima, the Federal Administrative Court ruled that the reactor should shut down within two years. In May 2014, however, the parliament approved the 2019 closure date with a 63 percent vote rejecting an early shutdown proposal. In January 2015, ENSI approved BKW's revised maintenance plan for Mühleberg, allowing the company to operate it until 2019. Ultimately, BKW decided to spend CHF 200 million on safety upgrades and to close the reactor in 2019.

In June 2023, the Swiss electorate approved the Federal Act on Climate Protection Targets, Innovation and Strengthening Energy Security[8]. Such Climate and Innovation Act sets the framework for Switzerland's climate policy. It contains targets for the reduction of greenhouse gas emissions in the most important sectors of buildings, transport, and industry. Currently, the Swiss parliament is discussing the revision of the Energy and Power Supply Act[9]. This so-called "Mantelerlass" aims to improve the framework conditions for the domestic expansion of electricity production from renewable energies and sets new and ambitious targets: 35 TWh annual production from "new renewables" (excluding hydropower) by 2035 and 45 TWh by 2050.

Table 3: Overview status of Swiss operating NPPs

Reactor Unit	Reactor Generation	Commercial Operation since	Age (age at approved operation by LTO)	Current LTO	Result LTO
Beznau-1	I	1969	54 (59)	2008 (2010), 2018 (2021)	Meets Swiss safety objectives for another 10 years
Beznau-2	I	1972	51 (56)	2008 (2010), 2018 (2021)	Meets Swiss safety objectives for another 10 years
Goesgen	II	1979	44	2018 (under review result expected in 2023)	
Leibstadt	II	1984	39	2022 (under review results expected in 2025)	

[5] https://www.ensi.ch/en/wp-content/uploads/sites/5/2017/12/ENSI-A03_E_web.pdf
[6] https://www.iaea.org/resources/databases/international-nuclear-and-radiological-event-scale
[7] https://www.ensi.ch/de/wp-content/uploads/sites/2/2023/04/CRR-Switzerland-FINAL_G51.pdf
[8] https://www.admin.ch/gov/en/start/documentation/votes/20230618/climate-and-innovation-act.html
[9] https://www.parlament.ch/de/ratsbetrieb/suche-curia-vista/geschaeft?AffairId=20210047

3 Method and Data

3.1 Nexus-e Overview

In this project, we use the Nexus-e modeling platform to develop scenarios for the Swiss electricity system by 2050. These scenarios are outcomes of computational optimization and present the option with the lowest total cost of power supply.

The modeling platform comprises different models describing the Swiss energy system embedded in the European power system. For this project, we use the model for the centralized power system (i.e., CentIv)[10] and the model for the decentralized power system (DistIv)[11]. CentIv and DistIv are used in interaction to find a scenario that provides sufficient electricity with the lowest total system cost for a given electricity demand. This optimization considers the existing infrastructure, such as power generation, storage options, and power grids. We examine the years 2030, 2040, and 2050. For example, for the year 2030, the current electricity infrastructure and the expected increase in electricity demand are considered. CentIv/DistIv then calculates the additional electricity infrastructure needed to meet the higher demand. The models then factor in the 2030 optimization results for the year 2040. To add electricity infrastructure, CentIv/DistIv can choose between the included technologies (so-called candidate units) based on their operating and investment costs and technical characteristics such as production profile or efficiency. Depending on the scenario, the additional electricity infrastructure must also compensate for the potential phase-out of nuclear power. Please note that we do not consider new nuclear plants and the extension of existing nuclear plants as candidate units but impose their construction and operating lifetime, respectively. So, both the construction of a new nuclear power plant and the operating lifetime of the existing ones are model inputs. A reason for this is that the results are sensitive to the costs assigned to candidate units, and for nuclear power plants the uncertainty in these costs are high.

In this process, CentIv is responsible for the central power infrastructure, such as wind farms, Alpine PV, and hydropower. DistIv, on the other hand, is responsible for the distributed power infrastructure, such as rooftop PV and local battery storages. We distinguish between a centralized and a distributed electricity system because investment decisions and local electricity prices are very different for the central and distributed infrastructure. For example, the profitability of a wind farm depends on the prices at which electricity can be sold on the electricity market, whereas the purchase decision for a rooftop PV system depends on self-consumption, feed-in tariff, and avoided electricity costs.

The balancing of supply and demand takes place every hour and is supported by flexible electricity generation and demand. For example, the flexibility of pumped hydro storage is used if the generation profiles of PV and wind do not match hourly demand. Other flexibility options include stationary and mobile battery storage, chemical energy sources such as natural gas with carbon capture and storage, and demand-side management. In addition to these high temporal requirements, there are also spatial requirements. The transmission grid is mapped in detail (298 power lines, 165 transformers), and load flows resulting from demand and supply are calculated. For this purpose, both the electricity demand and the generation plants are allocated to the respective nodes of the transmission network. The demand is allocated proportionally to the population. All centralized and decentralized electricity generators' locations and potentials are known and allocated to the nearest node.

As Switzerland is closely embedded in the European electricity grid and has substantial electricity trade with neighboring countries (France, Germany, Austria, and Italy), CentIv/DistIv also consider the direct European environment. For this purpose, the respective national electricity demand and electricity

[10] see CentIv Model Description
[11] see DistIv Model Description

generation and storage units are assigned to one node per country. This node is connected to the Swiss transmission grid and to the neighboring countries (e.g., France-Germany). The electricity trade with the neighboring countries is limited by the physical grid capacities and "net transfer capacities" (NTC) [MW]. The development of electricity generation in neighboring countries is not a result of CentIv/DistIv optimization but is given as input.

The input parameters for the model include a variety of techno-economic parameters (e.g., electricity demand, development of electricity generation capacity in neighboring countries). The model includes learning effects (decreasing prices of the technologies over time) and current subsidies (for example, feed-in tariffs and investment grants). The included technical potential of photovoltaics for rooftop installations is 47 GW based on Sonnendach data[12]. The included technical potential for wind power is set to 30 GW based on a recent BFE/Meteotest study.[13] The potential for biomass, including waste incineration, is set to 0.4 GW. We also assume that the electricity generation from hydropower (run-of-river, pumped hydro storage, hydro dams) increases slightly compared to today's levels. Electricity demand assumptions follow the "Zero Basis" scenario of the Energy Perspectives 2050+, which considers increasing electricity demand mainly due to the electrification of the transportation and heating sectors with electric vehicles and heat pumps. The development of the electricity generation capacities in the neighboring countries is based on the ENTSO-E scenarios. The NTCs are based on the latest ENTSO-E ERAA and are assumed to be identical for both directions (e.g., CH-FR, FR-CH). All assumptions and input data used in Nexus-e are described in the "Nexus-e Input Data and System Setup" report[14]. The main model output comprises installed electricity generation and storage capacities, hourly electricity generation and storage, imports and exports with neighboring countries, electricity dispatch prices, renewable energy curtailment, and total electricity system costs (excluding costs for the distribution grid).

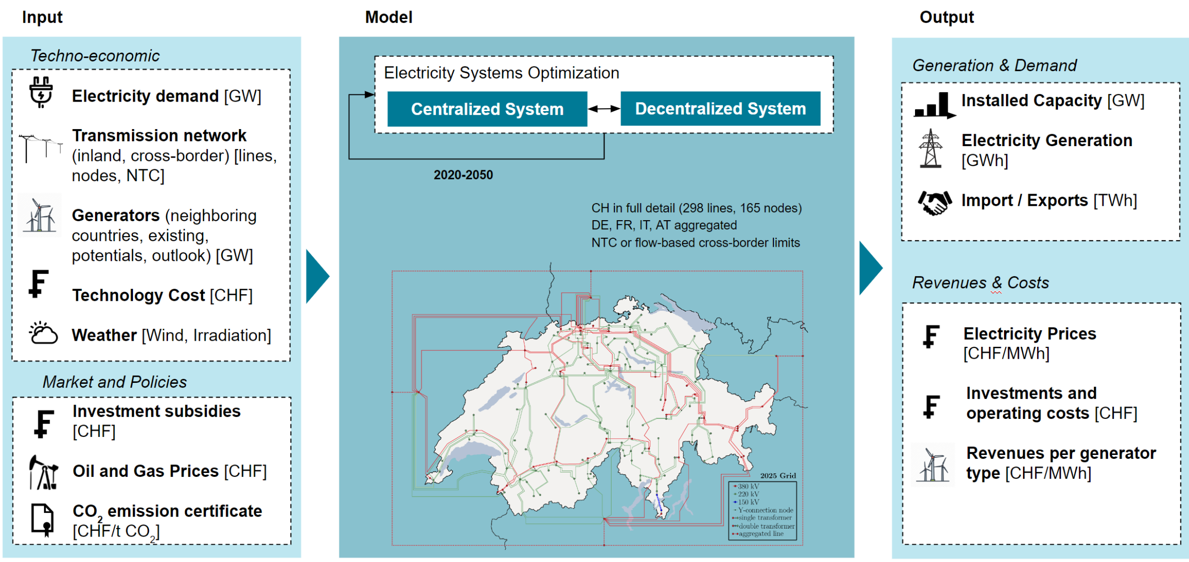


Figure 9: Nexus-e Overview

[12]see www.sonnendach.ch. We only allowed for rooftops with a good PV fit.
[13]see "Windpotenzial Schweiz 2022"
[14]see Nexus-e Input Data and System Setup

3.2 Modeling of Nuclear Power

3.2.1 Existing Nuclear Power Plants

In Nexus-e, we represent the four operating reactors, i.e., Beznau 1, Beznau 2, Leibstadt, and Goesgen. The operating lifetime is a scenario input to the model. Depending on the scenario, each nuclear unit can have varying operating lifetimes (see section 3.3). Also, we do not include the costs of a lifetime extension in the model but instead add the investment costs in the post-processing step. We do so as the costs for extending the operating lifetime of an NPP are challenging to calculate and come with high uncertainty. Generally, extending the operating lifetime comes with considerable costs due to necessary modernizations and safety upgrades. For example, since Beznau-1 and -2 have been commissioned, more than CHF 2.5 billion had to be invested in the safety and reliability of the two plants.[15] Another example is the Leibstadt NPP, for which Axpo has invested around CHF 1 billion since 2010 in safety and performance improvement. While the historical investments in modernization and safety upgrades are very plant-specific and include increases in power output, we estimate that a 10-year extension of a reactor has costs of around CHF 1 billion. This number is very uncertain and should be treated with caution.

To compare investments in technologies with different lifetimes and to account for the cost of capital, we calculate for each technology the “Equivalent Annual Cost”[16], which is the annual cost of owning, operating, and maintaining an asset over its lifetime. For all technologies, we use the same weighted cost of capital (WACC) of 5 percent, which takes into account the interest to pay for loaned money, the dividends to investors, and the down-paying of the principal. To compare, the WACC of the Swiss power utility Alpiq in the year 2019 was 4.3 percent.[17] We also calculate the equivalent annual cost for extending the NPP operating lifetime, which amounts to CHF 130 million per year. Note that the cost of capital thus increases the total costs of extending the lifetime of one reactor by ten years from (assumed) CHF 1 billion to CHF 1.3 billion.

Table 3 shows the most important techno-economic characteristics, which are assumed to be the same for all modeled nuclear reactors.

Table 4: Overview of techno-economic characteristic of modelled Swiss NPPs

Parameter	**Value**	**Unit**	**Source**
Operating and Maintenance Costs	28.9	CHF/MWhel	Annual Reports
Fuel Cost	6.1	CHF/MWhel	Annual Reports
Fuel Disposal Cost	9.1	CHF/MWhel	Annual Reports
Minimum capacity	30	%	Own estimate
Thermal efficiency	0.33	MWel/MWth	Annual Reports
Ramp rate	30	Capacity-%/h	Own estimate

For the variable costs, including operating and maintenance, fuel, and fuel disposal, we use the historical values provided by the annual reports of the Leibstadt and Goesgen NPPs.[18,19]

Existing nuclear power plants can ramp down and up to a certain extent. However, such a process of varying the power output typically comes with additional variable costs and decreasing efficiency. In Nexus-e, we cannot represent the dependency of variable costs and efficiency based on the power output of generators. We include a conservative ramp rate and a minimum operating capacity to avoid

[15] Nuklearforum Schweiz. 2022. “Investitionen in Den Langzeitbetrieb Prägen Die Stromproduktion 2021.” 2022. https://www.nuklearforum.ch/de/news/investitionen-den-langzeitbetrieb-praegen-die-stromproduktion-2021.

[16] see Investopedia

[17] Eric Knight. Review of pwc’s discount rate for alpiq holding sa.page 2. PwC, 2019.

[18] AKW Goesgen. Annual report goesgen. https://www.kkg.ch/de/ueber-uns/geschaeftsberichte-1031.html, 2023. Accessed:2023-06-30.

[19] AKW Leibstadt. Annual report leibstadt. https://www.kkl.ch/unternehmen/medien, 2023. Accessed: 2023-06-30.

a behavior that shows a too-pronounced up and down ramping. While this avoids daily up and down ramping, it prohibits the option of complete cold shutdowns during the summer.

We consider annual planned outages for nuclear, mostly due to required refueling. The duration and timing of these outages are model inputs and are based on historical data.[20,21] We assume that the planned refueling outages are occurring in the same period in all future scenario years, while for the historical years (i.e., 2020), we set the outages based on when they actually occurred.

3.2.2 New Nuclear Power Plants

We also consider a new NPP built at a given year. The techno-economic characteristics shown in Table 3 also apply to the new power plants. Like the existing reactors' operating lifetime, constructing a new NPP is an input to the model and not an endogenous decision of the model itself. We also do not include the investment costs in the model due to high uncertainty evolving around that value and instead, add such costs in a post-processing step. This project includes a new nuclear reactor with a nominal power output of 1,600 MW. We do so as the recently completed Finish generation III, Olkiluoto-3, also has a capacity of 1,600 MW.

The costs of constructing a new NPP are challenging to estimate. Currently, three new NPPs are under construction in Central Europe, with estimated costs ranging from 7'600 to CHF 12'600 per kWp.[22] All plants are already exceeding the initially planned budget. Outside Europe, construction costs are much lower, e.g., CHF 2'000 per kWp in Korea and CHF 3'200 per kWp in China. In terms of construction time, projects in Europe take 7.5 years, significantly longer than the global average. In April 2023, Finland's Olkiluoto 3, the first NPP in Europe in 16 years, began regular operation after 18 years of construction.[23] Other European NPPs have been under construction for 16 years (France) and 5 years (UK). The long construction times are partly due to the fact that they were "first-of-their-kind" plants and supply chain problems occurred during the Covid19 pandemic. For Switzerland, new NPPs can be expected to follow European examples in terms of construction costs and time.

We allocate the new NPP to the Mühleberg site, mainly due to its established connection to the transmission grid. In 2010, the ENSI also recommended the Mühleberg site as a suitable location for a new reactor.

3.3 Scenarios

We develop four base scenarios representing different options for nuclear power in Switzerland. We do so as there is uncertainty in the operating lifetime of Swiss NPPs. Currently, the regulation allows the existing plants to operate as long as they are determined safe by ENSI. Therefore, we consider a range of operating years. Whereas the construction of new NPPs is currently banned in Switzerland, we also investigate this option.

1. The reference scenario represents the status quo of Swiss NPP lifetime, meaning 60 years for Beznau I and II, and 50 years for Goesgen and Leibstadt.

2. In the NPP60 scenario, we assume that the two NPPs, Goesgen, and Leibstadt also operate for

[20] Vera Eckert. Switzerland market report: Swiss nuclear plant outages. Technical report, Reuters, 2016.

[21] Vera Eckert. Switzerland market report: Swiss nuclear plant outages and restarts. Technical report, Reuters, 2019

[22] Rothwell, Geoffrey. 2022. "Projected Electricity Costs in International Nuclear Power Markets." Energy Policy 164. https://doi.org/10.1016/J.ENPOL.2022.112905

[23] Lehto, Essi. 2023. "After 18 Years, Europe's Largest Nuclear Reactor Starts Regular Output." Reuters. 2023. Link to Reuters

60 years.

3. In the NPP6580 scenario, Beznau I and II operate for 65 years, and Leibstadt and Goesgen for 80 years.

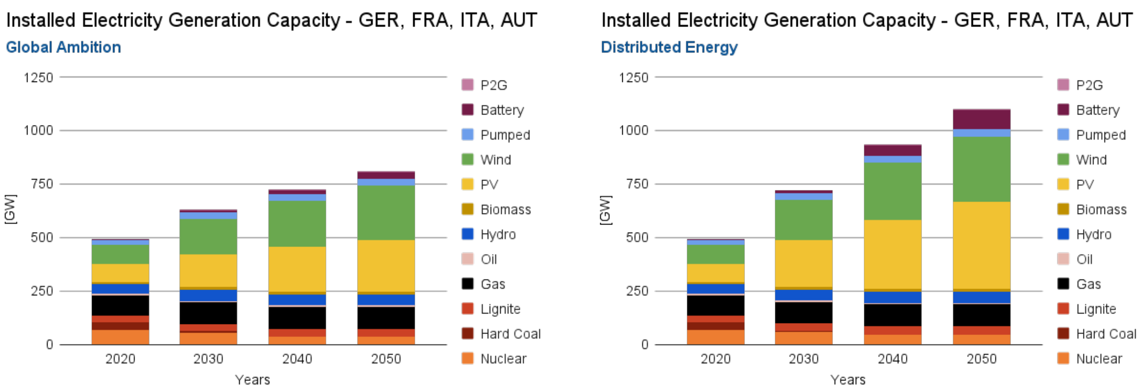
4. In the NPP60+ scenario, we assume that on top of a 60-year operating lifetime for all existing NPPs, a new NPP is also being constructed before 2040.

Table 5 depicts the operating time of all nuclear plants in these scenarios. All additional assumptions and input data used in Nexus-e are described in the “Nexus-e input data report”. Note that this study does not model if it is indeed possible to run a nuclear power plant for 80 years. This is taken as a model input, and the impact on the system is studied assuming that this would be possible.

Table 5: Overview of operation time Swiss NPPs

Reactor Unit	Status	Capacity [MW]	Commercial Operation since	Expected operation until			
				Reference	NPP60	NPP6580	NPP60+
Mühleberg	decommissioned	390	1972	2019	2019	2019	2019
Beznau I	In operation	380	1969	2029	2029	**2035**	2029
Beznau II	In operation	380	1972	2032	2032	**2037**	2032
Goesgen	In operation	1060	1979	2029	**2039**	**2059**	**2039**
Leibstadt	In operation	1275	1984	2034	**2044**	**2064**	**2044**
New NPP	-	1600	2040	-		-	**2100**

In addition to running the four baseline scenarios, we also conduct three sensitivity assessments. First, we test the impact of the developments in the neighboring countries on the feasibility of all scenarios. While in the baseline scenarios, we set the installed generation capacities and the demand in the neighboring countries on the European Network of Transmission System Operators for Electricity (ENTSO-E) ten-year network development plan (TYNDP) "Global Ambition" scenario, here we test the impact of switching to the "Distributed Energy" scenario[24] (see Figure 10). The "Global Ambition" scenario is based on an energy transition where the power supply is mainly based on centralized production facilities such as offshore wind. The "Distributed Energy" scenario, on the other hand, is based on a decentralized energy transition with a high level of electrification and investments in rooftop PV and battery storage. It also includes a substantially higher CO2 price.



(a) (b)

Figure 10: Installed generation capacities in ENTSO-E scenarios (10a) "Global Ambition" and (10b) "Distributed energy"

Second, we want to test the impact of electricity trading limitations on the feasibility of the four scenar-

[24] ENTSO-E, TYNDP 2020 Scenario Report, 2020

ios. The EU Clean Energy Package, which came into force in 2020, sets the rules for electricity trading and technical grid operation. It requires that by the end of 2025, all European transmission system operators make at least 70 percent of relevant electricity network capacity available for cross-border trading. However, it has not yet been regulated how third countries, such as Switzerland, are to be included in the 70 percent criterion. In an extreme case, this could limit cross-border capacities towards Switzerland and thus also electricity trading. Here, we reduce the net transfer capacities by 70 percent to illustrate such an extreme case.

Third, we test the impact of a higher electricity demand in Switzerland. To do so, we ramp up domestic hydrogen production to 2 TWh, 5 TWh, and 10 TWh by 2030, 2040, and 2050, respectively. This hydrogen is assumed to be used for the transport and industry sectors. We assume a monthly production profile over the year, which peaks in summer to make use of high electricity generation during this time.

4 Results

Detailed results for all scenarios are available on the interactive Nexus-e Webviewer at the following web address:

https://nexus-e.org/a-perspective-on-nuclear-power/.

The different scenarios can be selected from a drop-down menu and compared to each other.

Base Scenarios:

- *Reference*
- *NPP60*
- *NPP6580*
- *NPP60+*

Sensitivity on developments in the neighboring countries:

- Reference with Distributed Energy: *Reference DE*
- NPP60 with Distributed Energy: *NPP60 DE*
- NP6580 with Distributed Energy: *NPP6580 DE*
- NPP60+ with Distributed Energy: *NPP60+ DE*

Sensitivity on restricting electricity trading

- Reference with reduced NTC: *Reference NTC30*
- NPP60 with reduced NTC: *NPP60 NTC30*
- NPP6580 with reduced NTC: *NPP6580 NTC30*
- NPP60+ with reduced NTC: *NPP60+ NTC30*

Sensitivity on hydrogen demand

- Reference with hydrogen production: *Reference H2*
- NPP60 with hydrogen production: *NPP60 H2*
- NPP6580 with hydrogen production: *NPP6580 H2*
- NPP60+ with hydrogen production: *NPP60+ H2*

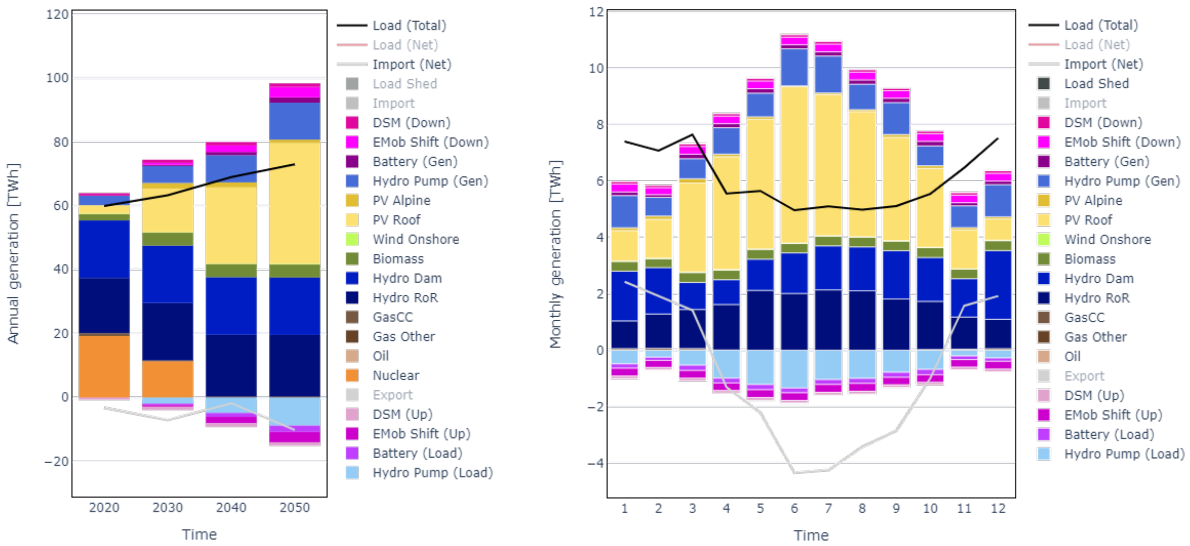
In the following, we present the results for the reference scenario (section 4.1). We then highlight the most important insights from the scenarios with extended operating lifetime of the existing NPPs (NPP60, NPP6580) in section 4.2 and the scenario with a new NPP (NPP60+) in section 4.3. Finally, we present the results for the sensitivities on the developments in neighboring countries, electricity trading, and hydrogen production (section 4.4).

4.1 Reference Scenario

4.1.1 Electricity Generation

In our reference scenario, we see a strong uptake of domestic electricity production (see Figure 11a) to cover the increase in electricity demand. Please note that the electricity demand is a model input (see Section 3 and is assumed to increase mainly due to the uptake of electric vehicles and heat pumps, whereas efficiency gains mitigate the increase. From the production side, we see the assumed nuclear power phaseout before 2050 (also a scenario input). Beznau I and Beznau II are phased-out after 60 years, Leibstadt and Gösgen after 50 years of operating lifetime. The largest portion of generating capacity that the model adds as part of its optimization is from rooftop PV. On top, batteries and alpine PV are being installed until 2050. Besides new installations, we also observe that the model utilizes existing units differently over time, especially hydro pumps, which are increasingly utilized to support the integration of intermittent renewable electricity generation.

Monthly electricity generation profiles indicate pronounced seasonal patterns (see Figure 11b). As expected, run-of-river hydro plants and rooftop solar PV achieve their peek electricity generation during the summer months. Electricity demand, however, is especially high during winter. It is important to note that although we see some curtailment during summer months, most excess electricity can be exported. This is because, following the ENTSO-E scenarios, neighboring countries focus on installing PV and wind power to produce carbon-neutral electricity. The latter produces more than 60 percent in the winter months. Also, solar power has almost zero marginal production costs, meaning on the European market it would be dispatched before the more expensive units, such as (synthetic gas), nuclear, or hydro (with exceptions).

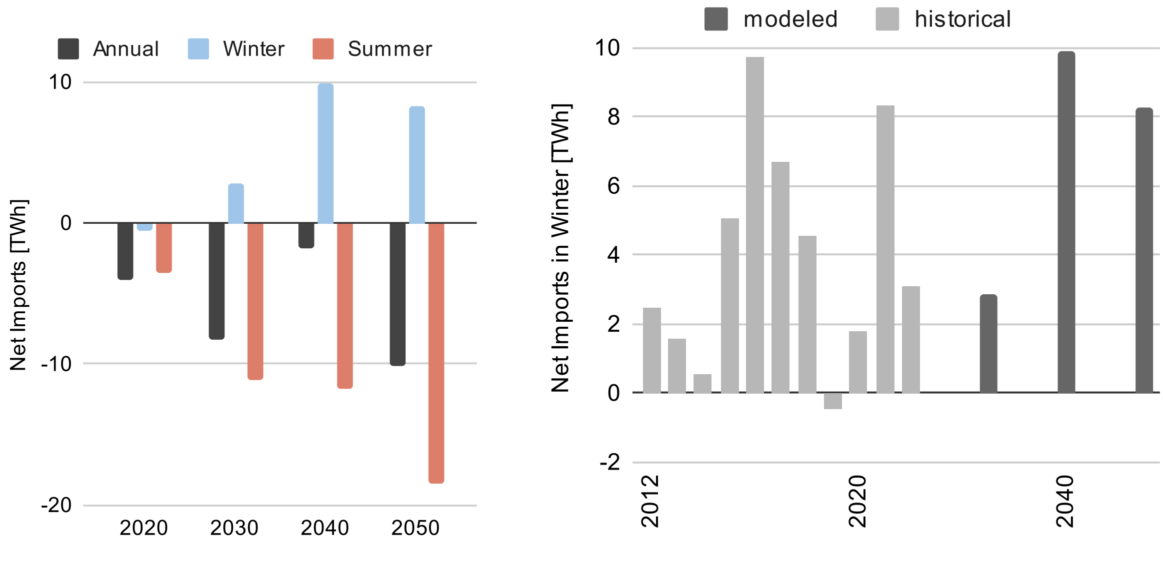


(a) (b)

Figure 11: Annual (11a) and 2050 monthly (11b) electricity generation in the reference scenario.

4.1.2 Imports and Exports

Such seasonally pronounced patterns also impact electricity trading. Annually, the net imports in all future years remain similar to does of today. This means that over a year Switzerland imports a similar amount of electricity as it exports. However, in winter, Switzerland's net imports from the neighboring countries increase; while the net exports also increase in the summer half year. Especially in the years after the nuclear phase-out, we observe the highest net imports in winter, increasing up to 10 TWh in 2040. Historically net winter imports were on average 4 TWh (see Figure 1b). Note that when comparing historical and simulated values for winter imports in 2020, we see that our model underestimates winter net imports by around 2 TWh.

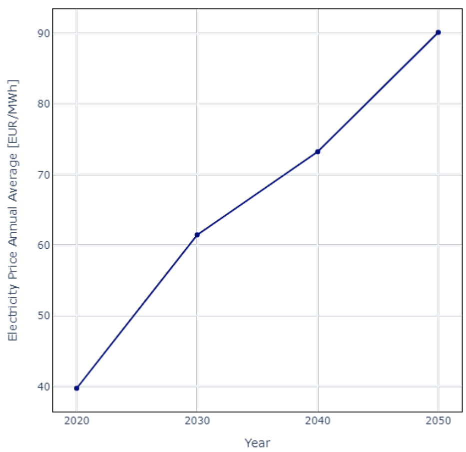


(a) (b)

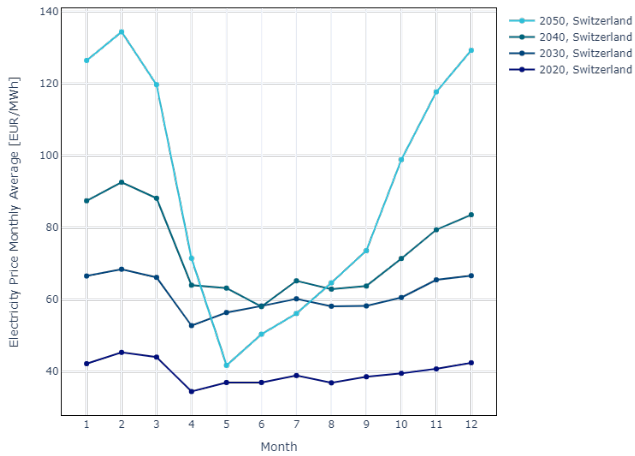
Figure 12: Development of annual, summer, and winter imports (12a) and the comparison with historical winter net imports (12b).

4.1.3 Prices and Revenues

Our results show the annual average electricity price is increasing until 2050 (see Figure 13a). The monthly electricity prices indicate why we see such an increase (see Figure 13b). Whereas the simulated prices for 2020 do not show substantial differences between months, in 2050 we observe a pronounced price spread between winter and summer months. Especially in winter, monthly prices increase substantially. This mainly comes from expensive power plants, such as synthetic gas units or natural gas-fired power plants with carbon capture and storage, which are running and price setting when wind and solar is not sufficient to cover all demand.



(a)



(b)

Figure 13: Annual (13a) and monthly (13b) electricity market prices in the reference scenario.

4.1.4 Total Costs of Electricity Supply

The system costs in the reference scenario are mainly composed of investment costs into rooftop PV and electricity trading with the neighboring countries. Cumulatively, by 2050, the total costs sum up to CHF 109.5 billion. Generally, system costs include investment costs, variable and fixed operating costs, cost of capital, and trading revenues and costs. Note that the system costs in this analysis do not include transmission or distribution grid costs.

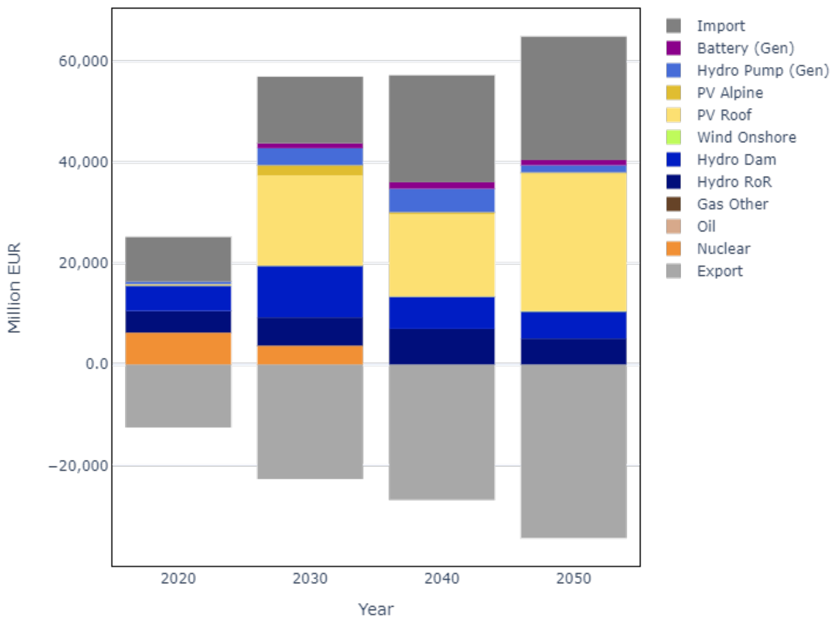


Figure 14: Nexus-e System Costs in the reference scenario

4.2 Extended operating lifetime of existing NPPs

4.2.1 Electricity Generation

Extending the operating lifetime of the existing nuclear power plants in the NPP60 and NPP6580 scenarios results in electricity generation from NPPs in 2040 and 2050, respectively. The impact on rooftop PV capacities is very small. Whereas in the reference scenario 35.3 GWp rooftop PV generate 37.8 TWh in 2050, in the NPP6580 scenario 34.9 GW rooftop PV generate 37.3 GW (see Figure 16. This can mainly be explained by the fact that the increasing electricity prices (see Figure 18) make investments into rooftop PV for residential and commercial building owners a profitable option. Also, we do not observe increase in PV curtailments with longer operating lifetime of NPPs.

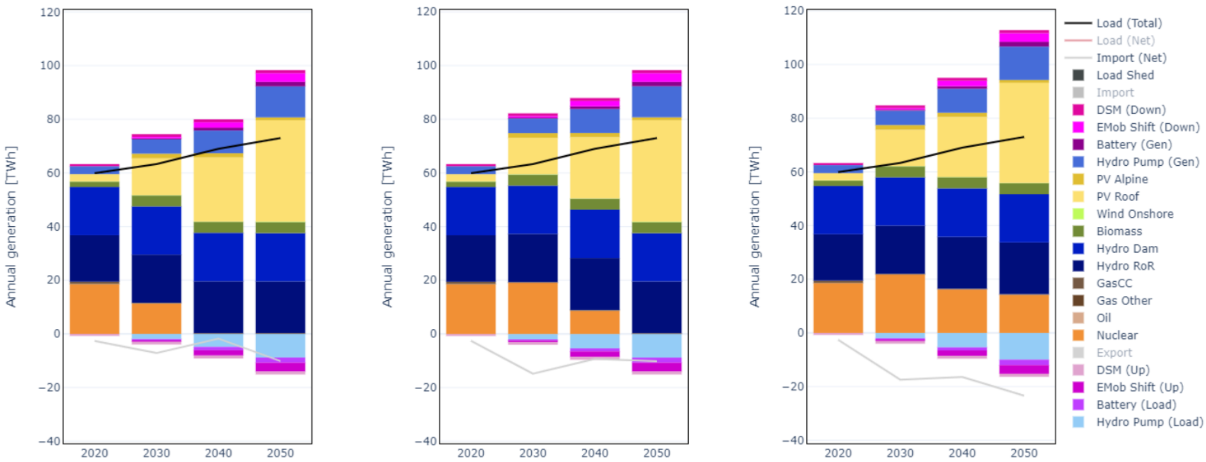
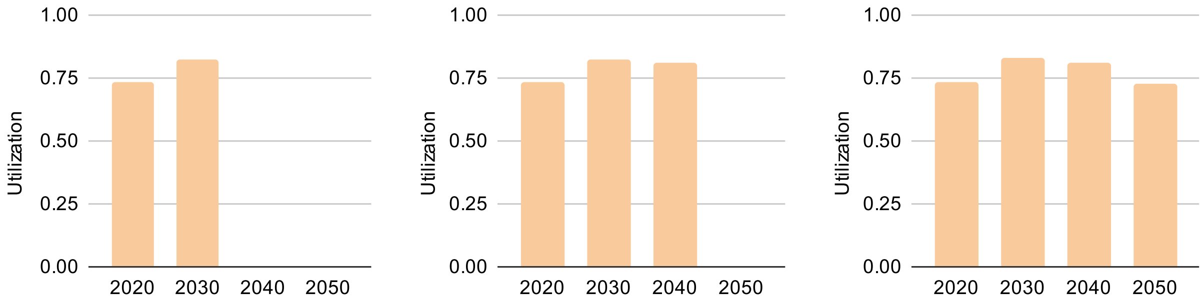


Figure 15: Electricity Generation for the Reference (left), NPP60 (central), and NPP6580 (right) scenarios.

However, we observe changes in the utilization of the NPPs (see Figure [**?**]). We define the utilization as the share of maximum possible NPP generation that would be achieved if the NPP would run in every hour with maximum output. While initially, utilization increases from 2020 to 2030 due to higher electricity market prices, starting from 2040 onward the utilization is decreasing. This is because, in Switzerland, high shares of PV result in low electricity prices in summer in which the dispatch of NPPs is decreasing. In winter, due to the high prices, the utilization of NPPs is still very high. Note that in all scenarios, we account for the planned outage times of the NPPs in the computation of the utilization.



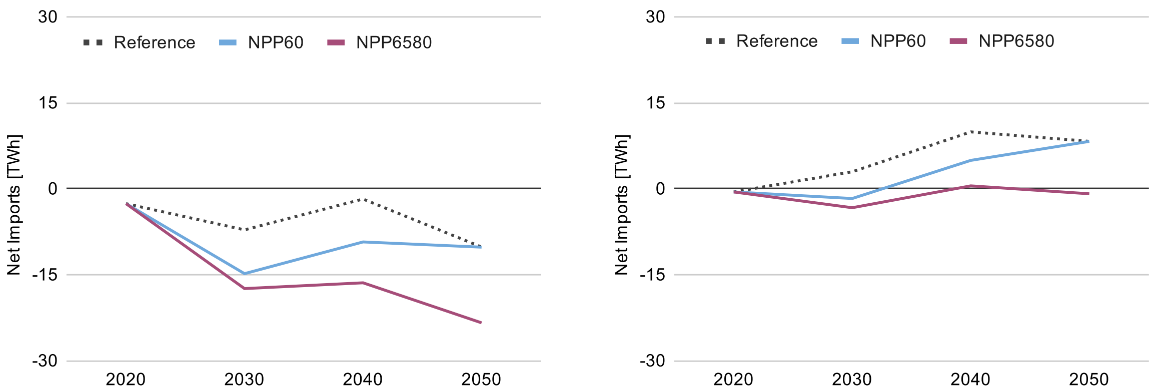
(a) (b) (c)

Figure 16: Annual utilization of existing NPPs in the reference (16a), NPP60 (16b), and NPP6580 scenarios (16c).

4.2.2 Imports and Exports

The operating lifetime has a strong impact on the net imports over the year and during the winter months (see Figure 17). In the NPP60 and NPP6580 scenarios, Switzerland becomes a strong electricity exporter (negative net imports) over the year. In 2050, the NPP60 scenario shows the same net imports as the reference scenario as all NPPs are already phased out in both scenarios. In winter, the reference scenario results in substantial increase in net imports over the years; however, the increase in operating time of NPPs helps to reduce the net imports. Especially in the NPP6580 scenario, net imports in winter can remain at today's level, even until 2050.

Note that net imports are the difference between electricity imported from and electricity exported to other countries. Although net imports over a certain period are zero, meaning that electricity trade is balanced, there are still in every hour imports and exports between Switzerland and its neighboring country. Imports and exports provide flexibility to balance out variations in demand and supply.

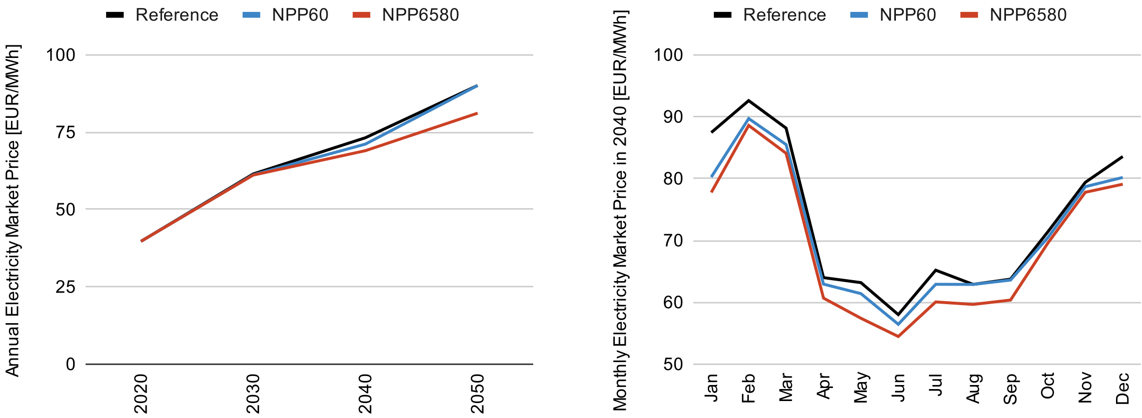


(a) (b)

Figure 17: Development of annual (17a) and winter (17b) net imports in the reference, NPP60, and NPP6580 scenarios.

4.2.3 Electricity Prices

The results of our scenarios that a longer operating time of NPPs also alleviates the increase in electricity prices over the simulated years (see Figure 18). For example, the NPP6580 scenario reduces the annual average electricity market prices by 9 CHF/MWh from 90 CHF/MWh to 81 CHF/MWh. The reason for the lower prices is mainly that the dispatch of more expensive and flexible capacities in the neighboring countries can be avoided during some hours. The monthly average electricity prices show that NPPs not only reduce the electricity price in winter but actually also in summer by producing electricity in days and nights during which renewable production is low.



(a) (b)

Figure 18: Development of annual (18a) and monthly (in 2050) (18b) electricity market prices in the reference, NPP60, and NPP6580 scenarios.

4.2.4 Total costs of electricity supply

In our scenarios, the total costs of electricity supply in Switzerland decreases with a longer operating time of NPPs. Figure 19 compares the electricity supply costs for the Reference, NPP60, and NPP6580 scenarios. The grey part of the bars in the figure depicts electricity supply costs for all technologies including investment costs, variable and fixed operating costs as well as revenues and costs for electricity exports and imports, respectively. The turquoise part of the bar depicts the assumed costs for having a longer NPP operating lifetime. In the NPP60 scenario, the total costs of electriciyt supply (including revision costs) decrease by CHF 3 billion to CHF 106 billion, compared to the CHF 109 billion in the reference scenario. Based on historical data, we here assume that the costs for extending the operating lifetime of one reactor by 10 years is around CHF 1 billion (see Section 3.2.1) plus financing costs. In total, we assume costs of CHF 3 billion in the NPP60 scenarios for the longer operating lifetime of both reactors.

For the NPP6580 scenario, the calculation is similar. Extending Gösgen and Leibstadt by an additional 20 years and Beznau 1 and 2 by additional 5 years, would result in CHF 6 billion by 2050 (excluding the costs after 2050). Although including this CHF 6 billlion for the lifetime extension, total electricity supply cost go down to CHF 98 billion. Due to the uncertainties in our assumption on the costs of NPP operating lifetime and whether this is actually also possible for the Swiss NPPs, these results have to be interpreted carefully.

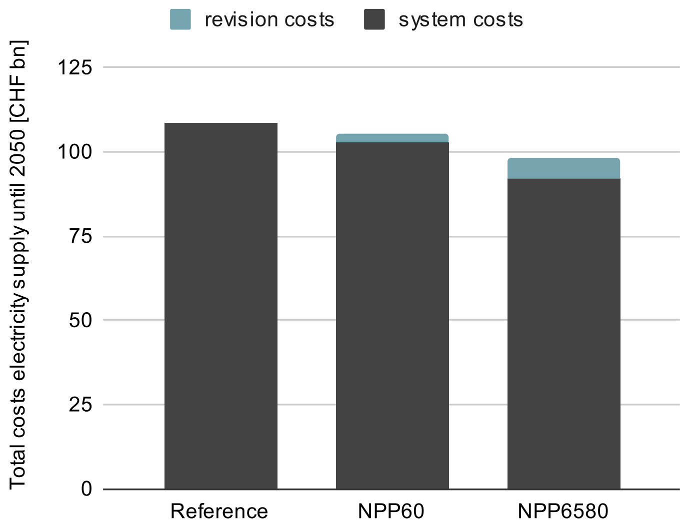
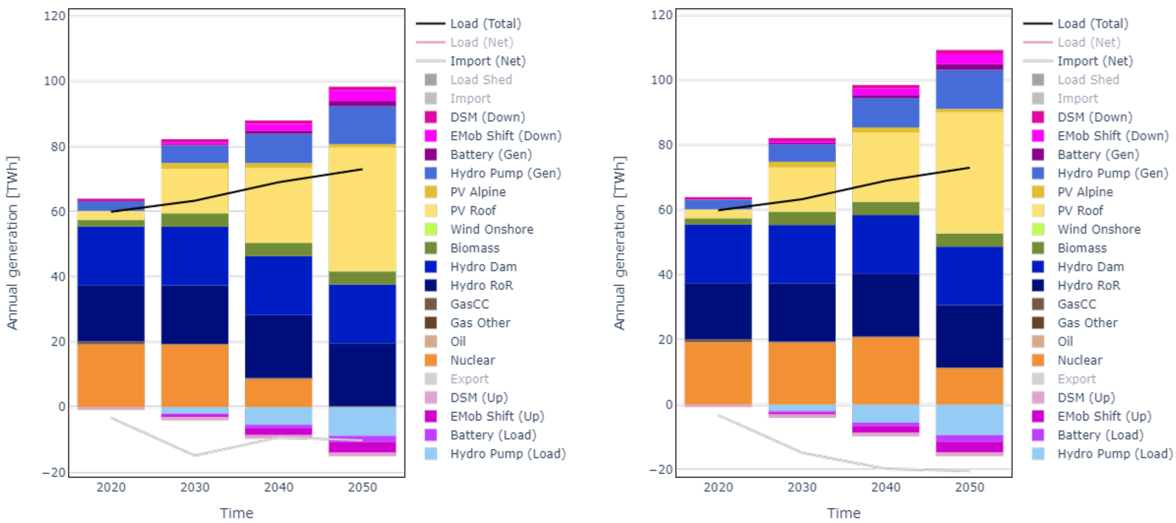


Figure 19: Total costs of electricity supply in the reference, NPP60, and NPP6580 scenarios

4.3 Construction of new NPPs

In the following, we present the result of the NPP60+ scenario, in which we add a new NPP with a capacity of 1.6 GW to the NPP60 scenario with 60 years operating lifetime for all existing NPPs. We then compare this scenario, with the NPP60 scenario, to single out the effect of a new NPP.

The electricity generation is similar for both scenarios except of the additional electricity provided by the new NPP, which amounts to 12.1 TWh in 2040 and 11.2 TWh in 2050 (see Figure 20). The lower generation in 2050 compared to 2040 can be explained by the reduced utilization of the NPP (see Section 4.2).



(a) (b)

Figure 20: Annual electricity generation in the NPP60 (20a) and NPP60+ (20b) scenarios.

Adding a new NPP reduces net imports in winter, especially in 2050, when all reactors, except the new NPP, are phased-out in both scenarios (NPP60, NPP60+) (see Figure 21a). Whereas in the NPP60 scenario, we see winter net imports of 5 TWh and 8 TWh in 2040 and 2050, respectively, in the NPP60+ scenario, electricity trading with the neighboring countries is almost balanced.

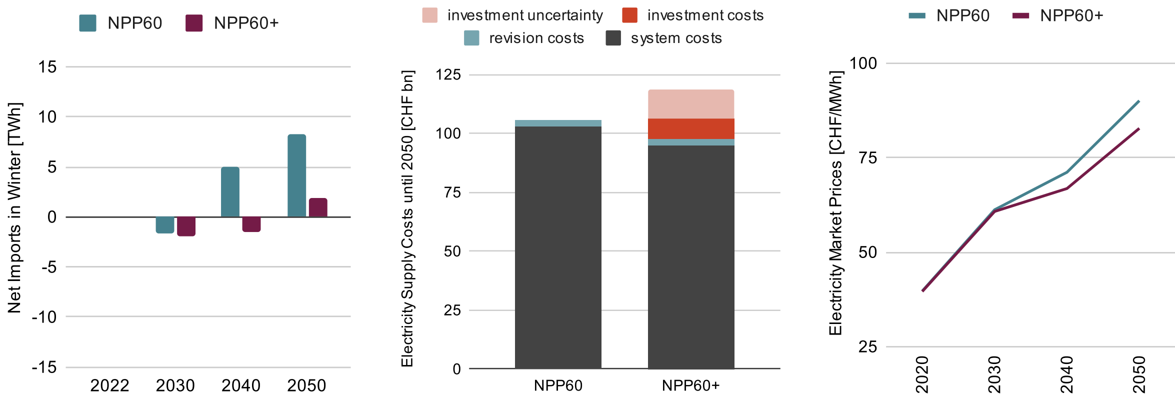
Similar to the revision costs for operating lifetime extensions, in the model, we do not directly include the costs for constructing a new NPP due to its uncertainty – instead we add the costs in a post-processing step. Without considering the costs for constructing a new NPP, electricity supply costs (grey parts of the plot) are CHF 9 billion lower in the NPP60+ scenario compared to the NPP60 scenario (Figure 21b).

However, whether the total electricity supply costs including new NPP costs are ultimately lower in the NPP60+ scenario compared to the NPP60 scenario, strongly depends on the assumed investment costs. The red parts of the bar represent the NPP investment costs: the darker red represents the lower range of the new NPP costs, assuming a minimum overnight construction cost of CHF 5 billion. The lighter red depicts the additional range of costs based on historical data for constructing NPPs in Europe (see Section 3.2.2), up to an addition of CHF 7.6 billion. Note that on top of the overnight construction costs, we also include the financing costs with a WACC of 5 percent. In the case of a overnight construction costs of CHF 5 billion, the financing costs increases total investment costs for a new NPP to CHF 8.5 billion. As the analysis only models the electricity system until 2050, we also only include costs and benefits until 2050. Therefore, economic advantages and drawbacks of nuclear electricity generation that go beyond 2050 are not accounted for.

We observe that with investment costs of NPPs in Europe that are currently under construction or have been recently completed, the NPP60+ scenario results in substantially higher costs compared to the scenario without a new nuclear power plant (i.e., NPP60). Only if investment costs of below CHF 5 billion per GWp can be achieved, constructing a new NPP starts to bring down Swiss electricity supply costs.

Although not shown here, please not that the NPP60+ scenario, even in case of extremely low investment costs that we observe outside Europe (e.g., CHF 3.2 billion CHF in China), results in higher costs of electricity supply compared to the NPP6580 scenario.

Figure 20b shows that a new NPP also reduced electricity market prices, similar to the NPP6580 scenario.



(a) (b) (c)

Figure 21: Comparison of the reference, NPP60, and NPP60+ scenarios in terms of net imports during winter (21a), total electricity supply costs (21b), and electricity market prices (21c).

4.4 Sensitivity Assessment

In addition to the four baseline scenarios, we also conduct three sensitivity assessments.

1. Second, we test the impact of electricity trading limitations on the feasibility of the four scenarios (NTC30). The new EU regulations (EU Clean Energy Package) could limit cross-border capacities towards Switzerland. We take an extreme case and reduce the NTCs to 30 percent of their original values and thus also restrict electricity trading.

2. First, we test the impact of the developments in the neighboring countries on the feasibility of all scenarios (TDE). While in the reference case, we base the installed generation capacity and the demand in the neighboring countries on the ENTSO-E "Global Ambition" scenario, here we test the impact of switching to the ENTSO-E "Distributed Energy" scenario[25] (see Figure 10).

3. Third, we test the impact of a higher electricity demand in Switzerland for the production of hydrogen (H2). To do so, we ramp up domestic hydrogen production to 2 TWh, 5 TWh, and 10 TWh by 2030, 2040, and 2050, respectively. This hydrogen is assumed to be used for the transport and industry sectors. We assume a monthly production profile over the year, which peaks in summer to make use of high electricity generation during this time.

4.4.1 Electricity Generation

Figure 22 shows the electricity generation in the reference scenario and all of the sensitivities performed for this scenario. Generally, the sensitivities affect the installed capacities and the electricity generation

[25] ENTSO-E, TYNDP 2020 Scenario Report, 2020

mix. In all sensitivities, we see more renewables being installed, in particular wind and alpine PV.

The reasoning for the additional renewable installations in the sensitivities is different. In the NTC30 scenarios, additional domestic winter electricity generation is being required as winter net imports are not possible to the same extent as in the base scenarios. To supply Swiss demand, wind power is being installed, as wind produces more electricity in winter than in summer. In the TDE sensitivity, generally electricity prices are higher from the alternative developments in the neighboring countries. Higher prices incentivize more investments into electricity generation, here alpine PV and wind. In the H2 scenario, the higher inland demand in summer also triggers more renewables, in this case alpine PV.

Additionally, we have performed the same sensitivities for the rest of the baseline scenarios (i.e.,NPP60, NPP6580, NPP+). In all of these sensitives we observe less investments in renewables. The generation results of these scenarios are not shown here; however, all results are available in our online webviewer.

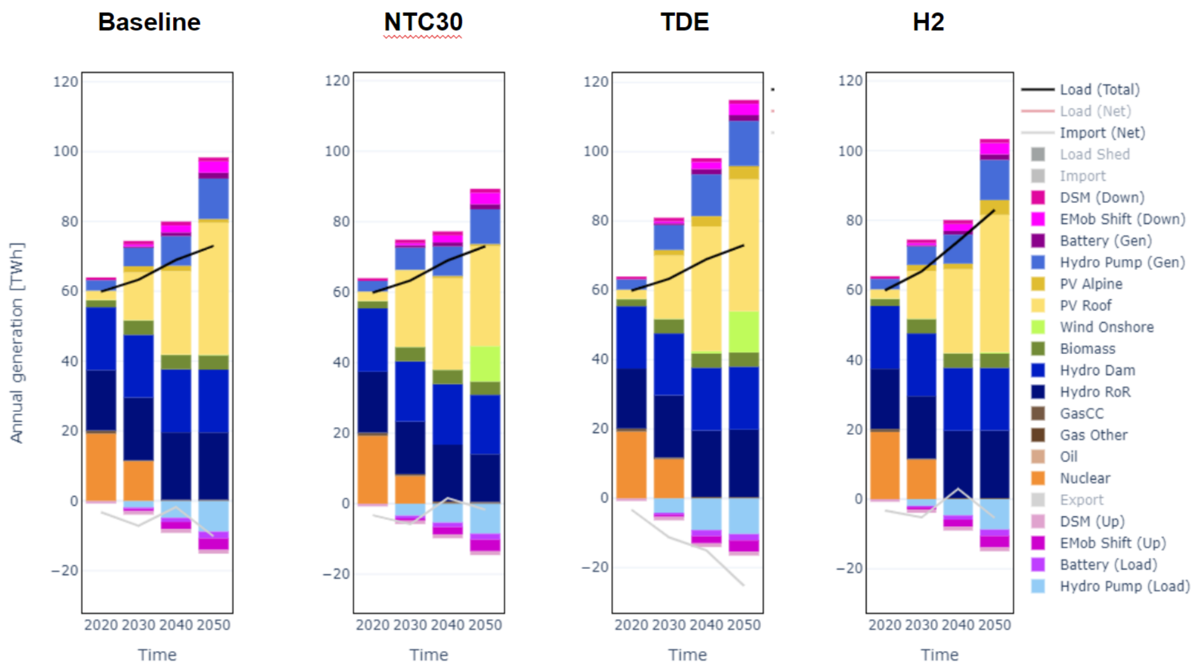
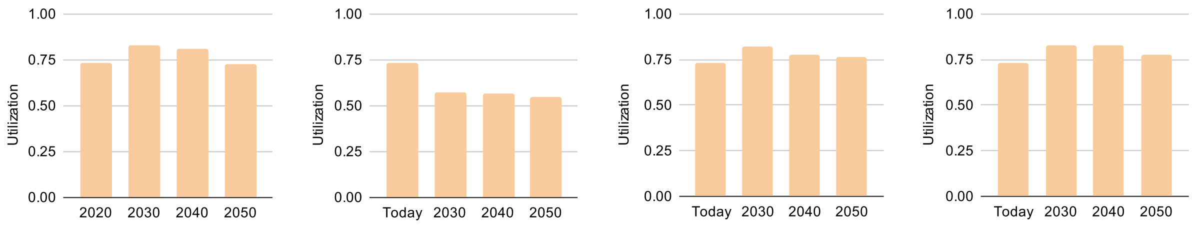


Figure 22: Electricity Generation in the baseline reference, reference NTC, reference TDE, and reference H2 scenarios

The sensitivities also affect the utilization of NPPs. Figure 23 shows the utilization of the NPPs for the NPP6580 scenario for the base and sensitivities. Especially for the reduced trading sensitivity, the utilization drops, down to nearly 50 percent, running in summer mostly at the minimum required output of 30 percent (except during the planned outages) and increasing again during the winter months. In the TDE and H2 sensitivities, nuclear utilization is slightly higher compared to the baseline as higher export prices or higher inland demand drive Swiss domestic electricity production.



(a) (b) (c) (d)

Figure 23: NPP utilization in the NPP6580 scenario in the baseline (23a) and the NTC30 (23b), TDE (23c), and H2 (23d) sensitivities.

4.4.2 Imports and Exports

Figure 24 shows the net imports for all baseline scenarios and their sensitivities. The different domestic electricity generation mostly explains the differences in the winter net imports. The additional electricity generation from alpine PV and wind lowers the winter net imports. Only with the higher electricity demand due to domestic H2 production, winter imports are not substantially affected. Also the effect of longer operating lifetime and construction of a new NPP is very similar across all sensitivities. It further reduces winter net imports in these years when higher nuclear capacity is available.

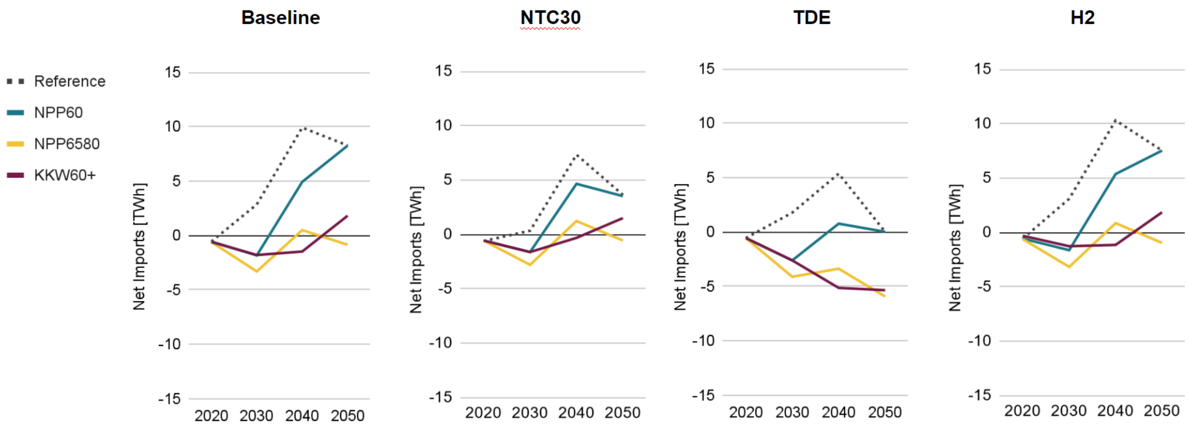


Figure 24: Winter Net imports in the baseline reference, reference NTC, reference TDE, and reference H2 scenarios

4.4.3 Electricity Prices

Figure 25 shows the electricity prices for all baseline scenarios and their sensitivities. We observe that the electricity market prices show different developments depending on the sensitivity. However, the effect of nuclear power on the results remains similar across all sensitivities. In the NTC30, electricity market prices are actually lower, compared to the reference scenario. This can be explained by the higher domestic renewable generation and a reduction of the influence that neighbouring countries have on the Swiss price (less electricity trading). In the TDE sensitivity, Switzerland also has higher renewable generation, but electricity market prices are higher in the neighboring countries which also affects Swiss market prices. This is why the TDE sensitivity shows generally higher prices. The prices in the H2 scenario are slightly higher compared to the baseline scenarios due to the higher domestic demand.

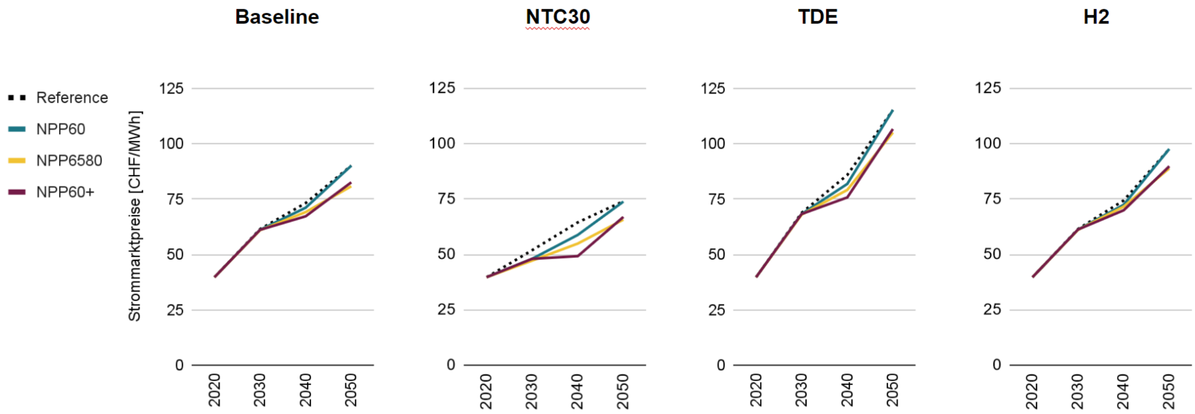


Figure 25: Electricity Prices in the baseline reference, reference NTC, reference TDE, and reference H2 scenarios

4.4.4 Costs of Electricity Supply

Figure 26 shows the cost of electricity supply for all baseline scenarios and their sensitivities. It is evident that the sensitivities also affect the system costs. Especially the reduction of the possible electricity trading (NTC30) has a strong impact on electricity supply costs. Comparing the reference baseline and the reference NTC30 scenarios, electricity supply costs are increasing by almost 50 percent and CHF 50 billion. This can be attributed mostly to the electricity trading, which in the reference scenario has a plus of CHF 29 billion while the NTC30 scenario has a minus of CHF 9 billion. While imports in winter are reduced, exports are also reduced substantially, especially in summer. In the TDE sensitivity system costs are also reduced. This is mainly because of two reasons: First, higher domestic electricity generation increases revenues from exports and reduces import costs. Second, higher prices in neighboring countries also increases export revenues. In the H2 scenarios, the system costs are slightly higher and can be understood as additional system costs to produce hydrogen in Switzerland. The impact on nuclear power on the system costs, however, remains very similar across the sensitivities. Across the simulated scenarios, extending the operating lifetime reduces system costs (with assumed revision costs) and constructing a new NPP increases system costs (with historical costs for new NPPs in Switzerland).

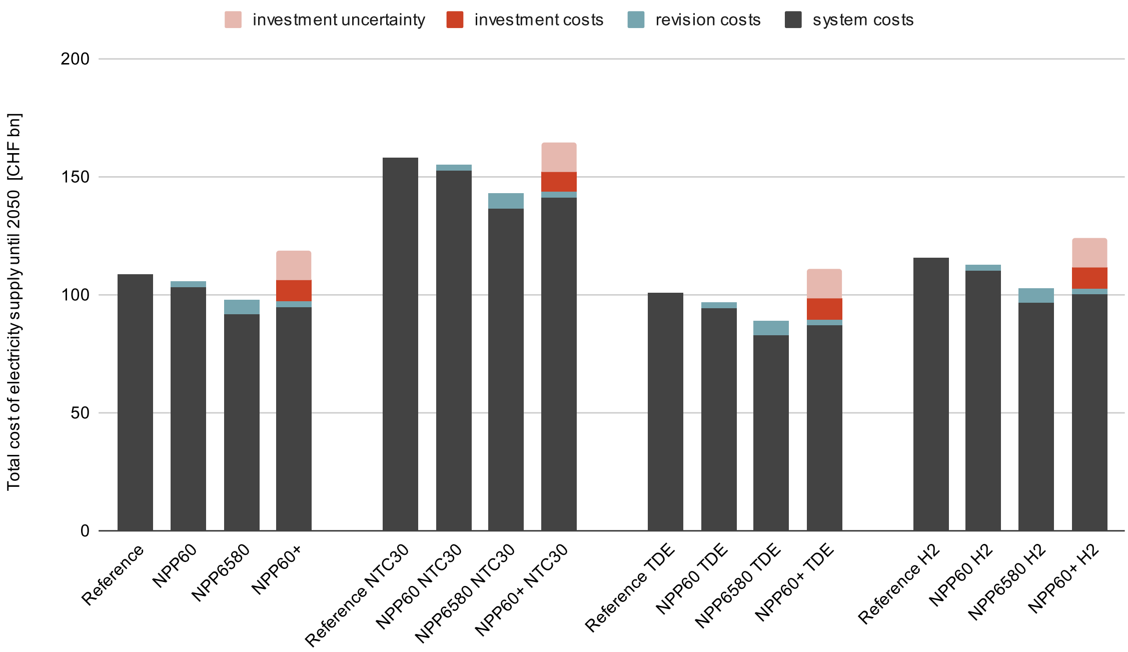


Figure 26: Cost of electricity supply in the baseline and sensitivity scenarios