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Flexibility provision from electromobility and buildings

Synthesis Report

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Flexibility provision from electromobility and buildings

Synthesis Report

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Disclaimer:

This report primarily presents research conducted within the PATHFNDR project, but includes selected external references where relevant to support, contextualize, or complement the findings. Detailed literature reviews can be found in the referenced papers and reports.

This report presents scenario-based results for Switzerland's energy system to 2050, focusing on the impacts of electric vehicle and heat pump flexibility. These are projections, not forecasts or predictions. They arise from empirical data and system modelling using least-cost optimization under the stated assumptions. Results depend on input data, socio-economic and technological assumptions, and methodological choices. They should therefore be interpreted as indicative "best estimate" values rather than precise figures, given uncertainties in technology uptake, prices, and regulation. The authors are responsible for the analysis and its interpretation.

AI tools have been used to assist in correcting grammar and style, as well as to rephrase certain sections for improved clarity and readability. The authors take full responsibility for the content of the final publication.

Contents

Nomenclature	vi
Kurzfassung	1
Executive Summary	10
Abstract	17
1 Introduction	18
2 What is flexibility from EVs and HPs used for?	21
2.1 System-level perspective	21
2.2 Distribution-level perspective	28
3 Quantifying flexibility from EVs and HPs	35
3.1 Quantifying heat pump flexibility	35
3.2 Quantifying electric vehicle flexibility	38
4 How can we enable flexibility from EVs and HPs?	41
4.1 Policy, regulation and business strategies	41
4.2 Operational and market mechanisms	43
4.3 Social acceptance	45
5 Future research	47
6 Stakeholder recommendations	48
Bibliography	51

Nomenclature

CO ₂	Carbon Dioxide
DSO	Distribution System Operator
EV	Electric vehicle
HP	Heat pump
HV	High Voltage
LV	Low Voltage
MPC	Model Predictive Control
MV	Medium Voltage
NL4	Network Level 4 (High Voltage/Medium Voltage Transformer Level)
NL6	Network Level 6 (Voltage-Regulating Medium Voltage/Low Voltage Transformer Level)
NL7	Network Level 7 (Low Voltage Level)
P&D	Pilot and Demonstration
PV	Photovoltaic
Q	Reactive Power
Q(V)	Reactive Power Control as a Function of Voltage
R&D	Research and development
sTES	Seasonal Thermal Energy Storage
TSO	Transmission System Operator
V	Voltage
V(P)	Voltage Control as a Function of Active Power
V1G	Smart charging or unidirectional controlled charging
V2G	Vehicle-to-Grid or bi-directional controlled charging

Kurzfassung

Kernaussagen

- **Flexibilität ist für das Energiesystem von grossem Wert**, da die Verschiebung der Nachfrage von Elektrofahrzeugen (EV, Electric Vehicle) und Wärmepumpen (WP) eine höhere Integration erneuerbarer Energien, niedrigere Systemkosten, geringere Netto-Stromimporte und niedrigere durchschnittliche Grosshandelsstrompreise ermöglicht sowie den zusätzlichen Kapazitätsbedarf bei Gaskraftwerken und Batteriespeichern verringern kann.
- **Flexibilität ist in erheblichem Mass verfügbar**, da EV und WP eine verschiebbare Nachfrage bieten: WP können die thermische Trägheit von Gebäuden und/oder Warmwasserspeichern nutzen, während EV Flexibilität sowohl innerhalb von Ladevorgängen als auch über verschiedene Ladestandorte hinweg bieten.
- **Eine flexibilitätsorientierte Planung** nutzt die Flexibilität der Endnutzerinnen und -nutzer, um den Bedarf an Netzausbau und -verstärkung zu verschieben oder zu reduzieren. Dies geschieht, indem die Last durch WP und das Laden von EV verlagert oder reduziert wird und die Einspeisung von Solarstrom mit nur geringen Erzeugungsverlusten begrenzt wird.
- **Flexibilitätsfreundliche Regulierung** ist entscheidend, um Endnutzerinnen und Endnutzer, Betreiber und Aggregatoren zu befähigen, Infrastruktur zu installieren (z.B. ein landesweites "Recht auf Laden" im Einklang mit Standards für intelligentes Laden), Automatisierung einzuführen (z.B. interoperable, flexibilitätsfähige Steuerungen) und aktiv an der Bereitstellung und Nutzung ihrer Flexibilität teilzunehmen (z.B. durch aktualisierte Tarife und verbesserten Marktzugang).
- **Dynamische und hybride Tarife** mit standardmässigem Opt-out und automatischer Steuerung können den Stromverbrauch von EV und WP auf Zeiten mit niedrigen Preisen und hoher Erzeugung erneuerbarer Energie verlagern, wodurch Flexibilität geschaffen, Spitzenlasten gesenkt und Netzausbau hinausgezögert werden können.

- **Die Teilnahme von Endnutzerinnen und Endnutzern an Flexibilität** steigt, wenn Programme die Planung automatisieren, eine direkte Laststeuerung auf Geräteebe-
nutzen, standardmässig eine Opt-out-Anmeldung mit klaren Übersteuerungsmöglichkeiten
vorsehen und Absicherungsverträge anbieten, während Komfort geschützt und Kosten
gesenkt werden.
- **Flexibilität auf Nachbarschaftsebene** koordiniert gemeinsam genutzte WP und die
thermische Trägheit von Gebäuden in einem gemeinsamen Wärmenetz, reduziert
Lastspitzen und Netzüberlastungen, erhält den Komfort, senkt Einstiegshürden und
eröffnet neue Einnahmequellen.
- **Die öffentliche Unterstützung für Flexibilitätsmassnahmen** ist insgesamt hoch und
gut konzipierte Programme, die Risiken verringern, den Komfort erhalten und Kosten
senken, können die Teilnahme in grossem Massstab ermöglichen.

Die Energiestrategie in der Schweiz erfordert eine rasche Elektrifizierung im Verkehrs- und Heizungssektor sowie die vollständige Dekarbonisierung der Stromversorgung. Die Erreichung des nationalen Ziels der Netto-Null-Treibhausgasemissionen bis 2050 hängt von der Integration grosser Mengen neuer erneuerbarer Energien ab, während gleichzeitig fossile Brennstoffe für Heizung und Verkehr schrittweise ersetzt werden. Derzeit stellt die Wasserkraft die wichtigste Quelle für Flexibilität auf Systemebene dar, während geregelte Elektroboiler das Hauptinstrument für Flexibilität auf Netzebene sind. Allerdings entwickeln sich WP und EV zunehmend zu wertvollen, ergänzenden Quellen für Flexibilität auf der Nachfrageseite – sowohl auf System- als auch auf Netzebene.

Dieser Bericht hebt die Rolle von WP und EV als zentrale Ermöglicher von Flexibilität hervor, die den Übergang zur Netto-Null-Zukunft sowohl durch Systemausgleich als auch durch Netzmanagement unterstützen. Die Flexibilität von WP und EV ist wichtig, weil sie eine zeitliche Verschiebung des Stromverbrauchs in Einklang mit der Erzeugung erneuerbarer Energien erlaubt, wodurch Systemkosten, Strompreise und -importe gesenkt und die Netzbelastung reduziert werden. So kann die Elektrifizierung im Rahmen des Schweizer Netto-Null-Pfads zuverlässig und kosteneffizient voranschreiten. Die Ausschöpfung des vollen Flexibilitätspotenzials erfordert technologische Innovationen, aktualisierte regulatorische und politische Rahmenbedingungen sowie verbesserte Markt- und Betriebsmechanismen. Entsprechend behandelt der Bericht zunächst das Flexibilitätspotenzial auf System- und Verteilnetzebene, analysiert anschliessend die Flexibilität von EV und WP, gefolgt von regulatorischen, politischen, betrieblichen und marktwirtschaftlichen Aspekten sowie Fragen der gesellschaftlichen Akzeptanz. Der Bericht schliesst mit einer Darstellung der Herausforderungen, Chancen und Empfehlungen für die beteiligten Akteure.

Auf einen Blick: Potenzial der Flexibilität von WP und EV auf Systemebene in der Schweiz bis 2050*

Szenariobasierte Modellresultate; die Werte sind ungefähre Angaben (keine Vorhersagen).

Alle Veränderungen werden im Vergleich zu einem "Both off"-Szenario ohne WP- oder EV-Flexibilität angegeben.

- Erhebliche verschiebbare Last (5 TWh durch WP und 3 TWh durch EV)
- Zusätzliche Integration erneuerbarer Energien (+4% durch vermiedene Abregelung von PV und Wind)
- Niedrigere Gesamtsystemkosten (nur WP: –2%, nur EV: –2%, kombiniert: –4%)
- Geringere Netto-Stromimporte (nur WP: –12%, nur EV: –10%, kombiniert: –22%)
- Tiefere durchschnittliche Grosshandelsstrompreise (nur WP: –5%, nur EV: –2%, kombiniert: –7%)
- Weniger benötigte Gaskraftwerkskapazität (nur WP: –8%, nur EV: –14%, kombiniert: –31%)
- Weniger benötigte Batteriespeicherkapazität auf Systemebene (nur WP: –11%, nur EV: –17%, kombiniert: –33%)

** Die Ergebnisse sind szenariobasierte Projektionen bis 2050 (keine Prognosen) aus Kostenoptimierungs-Modellen unter festgelegten Annahmen. Zahlen sind indikative Angaben und hängen von Daten, Methoden und Unsicherheiten bei Technologieakzeptanz, Preisen und Regulierung ab.*

Die in diesem Bericht präsentierten Ergebnisse und Analysen gehen, soweit nicht anders vermerkt, von einem fortgesetztes Abkommen zur Integration des Schweizer Stromsystems mit den Nachbarländern ("CH-EU Stromabkommen" [1]) aus und stehen im Einklang mit den geplanten Entwicklungen des Schweizer Energiesystems bis 2050, wie sie im aktuellen Mantelerlass zum Stromversorgungsgesetz / Energiegesetz dargestellt sind [2]), etwa Förderung von Flexibilitätsaggregation, dynamischen Netztarifen und Datenzugang. Der Fokus der Forschung liegt auf der Schweiz, der Stromhandel mit Nachbarländern wird auf Systemebene berücksichtigt. Wesentliche Regulierungsänderungen im Rahmen der Schweizer Energiestrategie (z.B. ein Wegfall der Integration der Schweiz in die EU-Elektrizitäts- und Ausgleichsmärkte durch das CH-EU-Stromabkommen [1]) würden die Rolle der EV-WP-Flexibilität verändern und ihren Beitrag langfristig möglicherweise noch wertvoller machen. Zukünftige Forschungsarbeiten sollen diese Optionen vertiefen.

Flexibilitätspotenzial auf Systemebene

Szenariobasierte Modellierungsergebnisse für das Jahr 2050 zeigen, dass die Flexibilität von WP und EV die Schweiz dabei unterstützen kann, ihre Ziele von 45 TWh erneuerbarer Energie aus nicht-wasserkraftbasierten Quellen und Netto-Null-CO₂-Emissionen zu erreichen. Eine umfassende Elektrifizierung führt jedoch zu einer erheblichen zusätzlichen Nachfrage. Bis 2050 wird der jährliche Stromverbrauch in der Schweiz – je nach Modellannahmen – auf 9 bis 17 TWh für WP und 11

bis 17 TWh für EV geschätzt (siehe vollständigen Bericht, Abschnitt 3). Im Vergleich zu einem geschätzten jährlichen Stromverbrauch ohne EV und WP von 53 TWh im Jahr 2050 bedeutet dies einen zusätzlichen Strombedarf von mindestens 17% für WP und 22% für EV, während dem der Endenergiebedarf insgesamt sinkt.

Wenn dieser zusätzliche Bedarf flexibel gesteuert wird, sind die Vorteile für das Energiesystem beträchtlich. Simulationen zeigen, dass das System im Jahr 2050 die verfügbare Flexibilität effizient nutzen kann: 26% der Schweizer WP-Nachfrage (4,5 TWh) und 20% der Schweizer EV-Nachfrage (3,4 TWh) werden verschoben – insgesamt also etwa 8 TWh verschiebbare Last. Zum Vergleich: Der Beitrag anderer Flexibilitätsquellen zur Lastverschiebung betrug in den vier untersuchten Szenarien bis zu 1,0 TWh bei Batteriespeichern, 8,2 TWh bei Netto-Stromimporten und 12,3 TWh bei Pumpspeicherkraftwerken.

Im Vergleich zu einem Szenario ohne Flexibilität aus WP oder EV zeigen die Ergebnisse deutliche Systemvorteile: WP-Flexibilität allein kann die Netto-Stromimporte um 12%, die Gesamtsystemkosten um 1,7% und die durchschnittlichen Grosshandelsstrompreise um 4,9% senken. EV-Flexibilität allein kann die Netto-Stromimporte um 11%, die Gesamtsystemkosten um 2,1% und die durchschnittlichen Grosshandelsstrompreise um 1,9% senken. Die kombinierte Flexibilität beider Technologien bietet zusätzliche Vorteile: rund 4% mehr Stromerzeugung aus erneuerbaren Energien durch vermiedene Abregelung von Photovoltaik- und Windstrom, 22% niedrigere Netto-Stromimporte, bis zu 4% geringere Gesamtsystemkosten und etwa 7% niedrigere durchschnittliche Grosshandelsstrompreise im Vergleich zu einem System ohne Flexibilität. Darüber hinaus reduziert die kombinierte Flexibilität von EV und WP auch den Investitionsbedarf erheblich: Gasbefeuerte Kraftwerkskapazitäten können um bis zu 31% verringert werden. Batteriespeicherkapazitäten um bis zu 33%. Diese Trends und positiven Auswirkungen auf Systemebene werden durch Simulationen mit anderen Stromsystemmodellen und Szenarien weitgehend bestätigt [3].

Flexibilitätspotenzial auf Verteilnetzebene

Auf der Verteilnetzebene kann die zunehmende Verbreitung von PV, EV und WP die Nieder- und Mittelspannungsnetze der Schweiz stark beanspruchen. Die Schweizer Verteilnetze sind derzeit nicht darauf ausgelegt, sehr hohe Anteile von Solarstrom, EV-Ladungen und WP zu bewältigen – es sei denn, es werden gezielte Flexibilitätsmassnahmen umgesetzt. Auf lokaler Ebene wird Flexibilität erforderlich sein, um kostspielige Netzverstärkungen zu reduzieren oder zu verschieben – insbesondere Transformatoren- und Kabelaufrüstungen, die infolge von Überlastungen und/oder Spannungsverletzungen notwendig werden könnten.

Die für über 50 Netzregionen durchgeführte Analyse zeigt, dass Flexibilität durch intelligentes Laden von EV und die Steuerung von WP die insgesamt erforderlichen Netzinvestitionen in städtischen Gebieten im Median um ~40% senken kann. Ebenso kann eine Begrenzung der PV-Einspeisung die erforderlichen Netzinvestitionen bis 2040 um ~40% in städtischen und ~50% in ländlichen Gebieten reduzieren, wobei der jährliche Energieverlust weniger als 3% beträgt, wenn die PV-Leistung auf 70% der maximalen Produktion begrenzt wird. Diese Ergebnisse verdeutlichen, wie wichtig es für die Versorgungsunternehmen ist, eine flexibilitätsorientierte Netzplanung umzusetzen, um Lastspitzen zu bewältigen und lokale Flexibilitätslösungen zu nutzen [4; 5; 6; 7; 8; 9; 10; 11; 12; 13]. Die mittleren Reduktionen beziehen sich auf die Investitionen, die bei traditionellen Planungsmethoden ohne Flexibilitätsmassnahmen erforderlich wären. Zu beachten ist, dass die dargestellten Ergebnisse

den maximalen Nutzen zeigen – basierend auf der Annahme, dass alle Eigentümerinnen und Eigentümer von WP, PV-Anlagen und EV-Ladeinfrastruktur Flexibilität bereitstellen. Gleichzeitig ist hervorzuheben, dass die Unsicherheit bei der Einschätzung der verfügbaren und zuverlässigen Flexibilität eine erhebliche Herausforderung für die Versorgungsunternehmen darstellt.

Flexibilität bei Elektrofahrzeugen

Flexibles Laden von EV ist eine wirkungsvolle Massnahme, um lokale Netzüberlastungen zu verringern und die Integration von PV zu erleichtern – insbesondere in städtischen Gebieten mit hohen Marktdurchdringungsraten. Die verfügbare Flexibilität variiert je nach Ort und Zeitpunkt und hängt sowohl von technologischen als auch von verhaltensbezogenen Faktoren ab. Eine zeitliche Abstimmung des Ladevorgangs von EV auf die PV-Erzeugung kann Abregelungen verringern und den Eigenverbrauch erhöhen. Das Laden am Arbeitsplatz bietet hierbei eine besondere Chance zur Lastverschiebung [14], da rund 40% der Fahrzeuge an Werktagen während der Spitzenzeiten der Sonneneinstrahlung in der Nähe von Arbeits- oder Bildungseinrichtungen parkiert sind [15]. Intelligentes Laden (V1G) und bidirektionales Laden (Vehicle-to-Grid, V2G) ermöglichen es EV, als Energiespeicher zu nutzen, indem sie Strom verschieben oder ins Netz zurückspeisen und so das Stromnetz unterstützen [16; 17]. Die V2G-Technologie bietet dabei zusätzliche Flexibilität, da sie es EV ermöglicht, Energie zurück in das Netz einzuspeisen. V2G kann die Abregelung von PV-Erzeugung auf Systemebene sogar noch stärker verringern als V1G, indem vor den Stunden mit hoher PV-Einspeisung Energie abgegeben wird, um zusätzlichen Speicher- und Ladekapazität zu schaffen, wenn die PV-Produktion am höchsten ist [18].

Flexibilität bei Wärmepumpen

Durch einen flexiblen Betrieb bieten WP ein erhebliches Potenzial zur Entlastung des Stromnetzes. Sie können so gesteuert werden, dass sie Spitzenlasten – insbesondere im Winter – vermeiden, indem sie die thermische Trägheit von Gebäuden und/oder thermische Energiespeicher (z.B. Warmwasserspeicher) nutzen, um den Heizbedarf zeitlich zu verlagern, ohne den Komfort zu beeinträchtigen. Aufgrund der hohen Speicherkapazität von Gebäuden kann die WP-Last bei einer Aussentemperatur von 0 °C für 2 bis 10 Stunden reduziert werden, während das Komfortniveau erhalten bleibt (bis zu 10 Stunden in sanierten oder neuen Gebäuden mit Minergie-Standard) [19]. Als Referenzwert kann eine durchschnittliche WP bei 0 °C etwa 7 kW über zwei Stunden verschieben, was einer verlagerbaren Energie von rund 14 kWh entspricht. Hochgerechnet auf alle Gebäude im Kanton Zürich würde dies einer verschiebbaren Last von rund 1,7 GWh entsprechen, wenn jedes Gebäude mit einer WP ausgestattet wäre.

Wird die Leistungsreduktion jedoch nicht koordiniert, kann dies Rebound-Effekte verursachen – also plötzliche Nachfragespitzen, die von den Netzbetreibern aktiv gesteuert werden müssen [19]. Eine vielversprechende Lösung stellen Ansätze auf Gemeinde- oder Quartiersebene dar, bei denen die thermische Trägheit mehrerer Gebäude koordiniert oder WP und PV-Anlagen gemeinsam für mehrere Liegenschaften eingesetzt werden. Dieses Konzept wurde im Pilot- und Demonstrationsprojekt "Nanoverbund" getestet, das seine Fähigkeit nachwies, die Flexibilität zu erhöhen, Netzüberlastungen und Spitzenlasten zu reduzieren und die Gesamteffizienz zu verbessern [20].

Regulatorische und politische Mechanismen

Die Regulierung und Politik für die Flexibilität auf der Nachfrageseite entwickeln sich derzeit von der Unterstützung einer "einfachen" Elektrifizierung hin zu einer "flexiblen" Elektrifizierung [21]. Trotz dieser Entwicklung bestehen weiterhin Lücken, insbesondere in Bezug auf die Zugänglichkeit und die Kosten der Infrastruktur und des Betriebs von EV und WP. Um die Systemvorteile zu erschliessen – jetzt, da die Technologie verfügbar ist – sollte eine flexibilitätsfreundliche Regulierung deren Installation, Automatisierung, Beteiligung und wirtschaftliche Nutzung von Flexibilität erleichtern.

Obwohl nationale Dekarbonisierungsziele festgelegt wurden, ist die regulatorische Landschaft der Schweiz weiterhin fragmentiert, und der Stand der Flexibilitätsbereitschaft ist im ganzen Land uneinheitlich. So fehlt der Schweiz beispielsweise eine landesweite Regelung zum "Recht auf Laden", ebenso wie verbindliche Anforderungen zur Einhaltung von Standards für intelligentes Laden und Interoperabilität. Dies schafft Hürden für Mieterinnen und Mieter z.B. in Mehrparteiengebäuden, die Zugang zu einer Ladeinfrastruktur benötigen [21]. Einige Schweizer Kantone bieten zwar Subventionen für V1G- und V2G-fähige Ladegeräte an, doch insgesamt bleibt die staatliche Unterstützung uneinheitlich, und die Kosten sind teilweise übermässig hoch (z.B. hohe Stationskosten, Tarifstrukturen, die noch nicht an die Flexibilitätsanforderungen angepasst sind, sowie Doppelbesteuerung der rückgespeisten Energie) [18; 21]. Das Verteilnetzbetreiber-Versorgermodell in der Schweiz bietet zwar Vorteile für die direkte Laststeuerung, die Abdeckung ist jedoch bislang begrenzt [21; 22]. Darüber hinaus bieten die meisten Versorgungsunternehmen derzeit keine dynamischen Tarife an, da sie nicht gesetzlich dazu verpflichtet sind. Das hindert Endnutzerinnen und Endnutzer daran, ihre Flexibilität anzubieten. Gezielte politische Massnahmen wie neue oder aktualisierte dynamische Tarife, ein klar definierter Marktzugang für Aggregatoren, freiwillige direkte Laststeuerung (Opt-in) sowie weitere Finanzierungsoptionen sind notwendig, um die Verbreitung von Flexibilitätslösungen zu fördern.

Beispiele aus Städten wie Basel, Luzern und Bern zeigen, wie kommunale Initiativen Flexibilitätslösungen in der Praxis umsetzen können – etwa das "Nanoverbund"-Konzept. Dabei entstehen Mikro-Wärmenetze auf Quartiersebene aus mehreren miteinander verbundenen Gebäuden, die eine gemeinsame Wärmenutzung ermöglichen, Flexibilität bündeln, neue Einnahmequellen für Versorgungsunternehmen erschliessen und gleichzeitig die Einstiegshürden senken [20; 23].

Betriebs- und Marktmechanismen

Über die politische Unterstützung hinaus sind gut funktionierende Strommärkte entscheidend für die Integration von Flexibilitätsdiensten. Flexible Lasten können von einer Vielzahl von Akteuren gesteuert werden – etwa von Netzbetreibern, Aggregatoren, Energieversorgern oder Prosumenten –, die dieselben Lasten kontrollieren. Dies erfordert Koordination und Prioritätsregeln, um widersprüchliche Signale und Verstösse gegen Netz- oder Gerätevorschriften zu vermeiden.

Die direkte Steuerung flexibler Lasten durch Energieversorger oder Aggregatoren kann effiziente Ergebnisse erzielen, steht jedoch vor praktischen Herausforderungen in Bezug auf Datenschutz, Infrastrukturkosten und Akzeptanz durch die Verbraucherinnen und Verbraucher [21; 24]. Die Effizienz des Lastmanagements im Falle einer direkten Steuerung hängt davon ab, wie präzise dessen Auswirkungen auf das Stromnetz berücksichtigt und gegen die Effekte auf Grosshandels- und Ausgleichsmärkte abgewogen werden.

Dynamische Preismodelle können Anreize schaffen, den Betrieb von WP und das Laden von EV auf optimale Zeiten zu verlegen. Diese Modelle sind weniger eingreifend als die direkte Laststeuerung, erfordern jedoch regulatorische Anpassungen, um die Verfügbarkeit für Endverbraucherinnen und Endverbraucher auszuweiten. Dazu kommen weitere Herausforderungen im Zusammenhang mit der sozialen Akzeptanz [21]. Hybride Tarifmodelle, die dynamische, verbrauchsabhängige Preise mit kapazitätsbasierten Gebühren kombinieren, können dazu beitragen, eine Überkoordination automatisierter Lasten zu verhindern und die Netzbelastung zu stabilisieren [25].

Darüber hinaus stellen Profilverträge, in denen Verbraucherinnen und Verbraucher ihren Stromverbrauch im Voraus festlegen, eine vielversprechende Option dar, um Preisschwankungen zu reduzieren und gleichzeitig Anreize für die Teilnahme an Flexibilitätsprogrammen zu bieten [26]. Zudem können Aggregatoren und Energieversorger durch das Einbringen der aggregierten Flexibilität ihrer steuerbaren Lasten in Day-Ahead- und Intraday-Auktionen die Stromkosten für ihre Kundschaft senken und die Systemeffizienz steigern [27].

Soziale Akzeptanz

Die Akzeptanz durch die Verbraucherinnen und Verbraucher ist ein weiterer entscheidender Faktor für den Erfolg von Flexibilitätsinitiativen. Umfragen zeigen, dass die Präferenzen sehr unterschiedlich sind: Während einige Kostenersparnisse priorisieren, legen andere mehr Wert auf Komfort und Bequemlichkeit [28]. Etwa 30% der Schweizer Bevölkerung nehmen gewisse Komforteinbussen in Kauf, um Stromkosten zu senken, während 70% Flexibilität nur anbieten, wenn ihr Komfort nicht beeinträchtigt wird [28]. Zudem bevorzugen die meisten Verbraucherinnen und Verbraucher eine direkte Steuerung einzelner Geräte gegenüber Lastmanagement-Ansätzen, die ihren Gesamtstromverbrauch einschränken [28]. Automatisierung reduziert die Abneigung gegenüber Preisschwankungen, indem sie die Planung im Hintergrund übernimmt. Dadurch werden dynamische zeitvariable Tarife etwa so akzeptabel wie statische Tarife [29]. Eine Opt-out-Option (Standardoption) erhöht die Teilnahmequote im Vergleich zu Opt-in-Modellen [30]. Der Komfort kann durch Geräteeinstellungen mit einfachen Übersteuerungsoptionen geschützt werden (z.B. durch die Festlegung eines Mindestladestands für EV oder eines Temperaturbereichs in Gebäuden). Vertragsmenüs (z.B. etwa Pauschaltarife mit automatischer direkter Laststeuerung oder verbrauchszeitabhängige Tarife für nicht automatisierte Nutzerinnen und Nutzer) können unterschiedlichen Präferenzen gerecht werden und Rebound-Spitzen vermeiden [31]. Schliesslich können Profilverträge die Rechnungsvolatilität absichern und gleichzeitig Anreize für Lastverschiebungen und -reduktionen bieten, was die Akzeptanz bei risikoaversen Haushalten erhöht [26; 32].

Die Berücksichtigung dieser Präferenzen ist entscheidend für die Entwicklung wirksamer Flexibilitätsprogramme, da Umfragen zeigen, dass die Schweizer Öffentlichkeit das flexible Laden von EV und die Einbindung von WP generell befürwortet [33].

Herausforderungen und Chancen

Mehrere Faktoren stehen der vollständigen Ausschöpfung des Flexibilitätspotenzials von WP und EV weiterhin im Weg. Auf technischer Ebene sind die Verteilnetze in der Schweiz nicht dafür ausgelegt, eine flächendeckende Elektrifizierung zu bewältigen, was das Risiko lokaler Überlastungen und kostspieliger Netzverstärkungen mit sich bringt. Darüber hinaus bestehen weiterhin politische Lücken, etwa das Fehlen eines landesweiten "Rechts auf Laden", das mit Standards für intelligentes Laden

kompatibel ist, die langsamen Fortschritte bei der Einführung dynamischer Tarifstrukturen und die uneinheitliche Unterstützung für flexibilitätsfähige (d. h. automatisierte und steuerbare) Infrastrukturen. Hohe Anfangsinvestitionen für EV und WP sowie Bedenken hinsichtlich Komfort und Bequemlichkeit bei den Verbraucherinnen und Verbrauchern schränken die Verbreitung von Flexibilitätslösungen zusätzlich ein.

Zur Überwindung dieser Hindernisse bietet sich eine Kombination mehrerer Lösungsansätze für die Nachfrageseite an: (1) V1G-Strategien und, wo kosteneffizient, V2G-Strategien; (2) gesteuerter Betrieb von WP, der die thermische Trägheit von Gebäuden, Wärmespeicher und gemeinschaftliche Wärmenetze nutzt; (3) eine flexibilitätsfreundliche Regulierung, die es Endnutzerinnen und Endnutzern, Betreibern und Aggregatoren erleichtert, teilzunehmen und ihre Flexibilität bereitzustellen; (4) dynamische und hybride Tarifmodelle, die Flexibilität belohnen; sowie (5) erweiterter Marktzugang für Aggregatoren, um Flexibilitätsdienstleistungen in Grosshandels- und Ausgleichsmärkte zu integrieren. Die Einführung flexibilitätsorientierter Planungsrahmen im Verteilnetz ermöglicht es Versorgungsunternehmen, kosteneffiziente Flexibilitätsoptionen zu identifizieren, die Investitionen in Netzinfrastruktur aufschieben oder reduzieren können. In Kombination können diese Lösungen der Schweiz helfen, die Verbreitung von EV und WP zu beschleunigen, ihre Dekarbonisierungsziele zu erreichen, sie nahtlos in die Verteilnetze zu integrieren und zusätzliche Dienstleistungen für höhere Netzebenen bereitzustellen und dabei gleichzeitig Vorteile für Verbraucherinnen, Verbraucher und Versorgungsunternehmen schaffen.

Zusammenfassung und zukünftige Arbeiten

Der vollständige Bericht quantifiziert die Beiträge der Flexibilität von WP und EV im Detail, identifiziert die wichtigsten Herausforderungen bei ihrer Integration und skizziert mögliche Lösungen sowie Handlungsoptionen für die beteiligten Akteure. Interessengruppen in der gesamten Schweiz – darunter politische Entscheidungsträger, Stromnetzbetreiber, EV- und WP-Anbieter, Flexibilitätsaggregatoren, Kantone, Gemeinden sowie Endnutzerinnen und Endnutzer – können die in diesem Bericht vorgestellten PATHFINDER-Forschungsergebnisse stützen, um den Wert der Flexibilität von EV und WP, die Hindernisse für ihre Einführung sowie die nächsten erforderlichen Schritte zu verstehen, damit ihr volles Potenzial in der Schweiz ausgeschöpft werden kann.

Zukünftige Forschungsarbeiten sollten insbesondere das Verständnis der Synergien zwischen der Flexibilität von EV und WP, der Hürden bei ihrer Einführung, des Nutzerverhaltens sowie der praktischen Umsetzung vertiefen, um eine skalierbare Integration in das Schweizer Energiesystem zu fördern.

Empfehlungen an die Interessengruppen

- **Bund:** Förderung der Flexibilitätsbereitschaft durch die kombinierte Einführung von EV und WP, Einführung eines landesweiten "Rechts auf Laden" in Verbindung mit der Vorgabe flexibilitätsfähiger Steuerungen und Standards für intelligentes Laden, Verpflichtung der Energieversorger zur Angebotserstellung dynamischer Tarife und Angleichung der Marktregeln zur Ermöglichung der Teilnahme aller Akteure an Flexibilitätsdienstleistungen, mit dem Ziel der Senkung der Systemkosten, der Reduktion der Netto-Stromimporte sowie der Unterstützung der Integration erneuerbarer Energien.
- **Kantone und Gemeinden:** Förderung der lokalen Flexibilität durch die Schaffung von Anreizen für steuerbare WP, gemeinsame Wärmenetze und intelligentes Laden von EV (V1G/V2G), Ermöglichung einer Skalierung der Beteiligung, einer Reduktion der Netzbelastung sowie der Erschliessung neuer Einnahmequellen für Endnutzerinnen und Endnutzer.
- **Übertragungsnetzbetreiber:** Koordination mit den Verteilnetzbetreibern zur Sicherstellung der Unterstützung von Systemausgleich und lokalem Netzmanagement durch flexible Ressourcen, Beitrag zur Kostensenkung und Verbesserung der Netzstabilität.
- **Verteilnetzbetreiber/Versorgungsunternehmen:** Sicherstellung der Verfügbarkeit von Netzmodellen für Niederspannungsnetze (Netzebene 7) zur Durchführung von Netzsimulationen, Ermöglichung einer wirksamen Einführung flexibilitätsorientierter Planungsrahmen für die Netzinfrastruktur, welche die Flexibilität der Endnutzerinnen und -nutzer nutzt, um die Notwendigkeit von Verteilnetzverstärkungen und -ausbauten zu verschieben oder zu reduzieren durch (i) Lastverschiebung und/oder Lastreduktion infolge von WP und EV-Ladevorgängen, (ii) Begrenzung der PV-Einspeisung sowie (iii) Berücksichtigung der Spannungsstützung durch PV-Anlagen.
- **Aggregatoren und Energieversorger:** Skalierung dynamischer und hybrider Tarife mit Standard-Opt-out, Automatisierung, direkter Laststeuerung auf Geräteebe und Verträgen zur Risikoabsicherung zur Steigerung der Beteiligung der Endnutzerinnen und Endnutzer, Reduktion der Beschaffungsrisiken, Erschliessung neuer Einnahmequellen und Aufbau skalierbarer Geschäftsmodelle durch Aggregatoren.
- **Technologieanbieter und Hersteller :** Bereitstellung flexibilitätsfähiger Geräte mit offenen Standards (z.B. SmartGridready), automatisierten Steuerungen und Messschnittstellen zur Gewährleistung eines flexiblen, netzfreundlichen Betriebs, Erweiterung des Marktzugangs, Förderung der Interoperabilität und Steigerung des Gerätwerts durch die Teilnahme an Flexibilitätsdienstleistungen.

Der vollständige Bericht enthält detaillierte, auf die einzelnen Interessengruppen zugeschnittene Empfehlungen.

Executive Summary

Key messages

- **Flexibility is valuable for the energy system** as shifting electric vehicle and heat pump demand can enable higher renewable integration, lower system costs, lower net electricity imports, and lower average wholesale electricity prices, and reduce the additional capacity needed in gas plants and batteries.
- **Substantial flexibility is available** as electric vehicles and heat pumps offer shiftable demand: heat pumps can exploit buildings' thermal inertia and/or hot water storage, and electric vehicles can use flexibility within charging sessions or across charging locations.
- **Flexibility-aware planning** leverages end-user flexibility to defer and reduce the need for distribution grid upgrades by shifting and/or reducing the load from heat pumps and charging of electric vehicles, and limiting the power fed back to the grid by solar photovoltaics with modest losses in the energy production.
- **Flexibility-ready regulation** is key to enabling end-users, operators and aggregators to install infrastructure (e.g., nationwide "right to charge" compliant with smart charging standards), automate (e.g., interoperable, flexibility-ready controls), better participate and benefit from offering their flexibility (e.g., updated tariffs and market access).
- **Dynamic and hybrid tariffs** with default opt-out and automated control can shift the electricity consumption of electric vehicles and heat pumps to hours with low prices and high generation of renewable energy, delivering flexibility, cutting peaks, and deferring grid expansion.
- **End-user flexibility participation** scales when programs automate scheduling, use appliance-level direct load control, default to opt-out enrolment with clear overrides, and offer risk-hedging contracts, while protecting comfort and cutting costs.
- **Neighbourhood-scale flexibility** coordinates shared heat pumps and building thermal inertia in a common heating network, reducing peaks and grid congestion, maintaining comfort, lowering participation barriers, and enabling new revenue streams.
- **Public support of flexibility policies** is generally strong, and well-designed flexibility programs that reduce risk, protect comfort, and cut costs can scale participation.

Switzerland's energy transition requires the rapid uptake of electrification in transportation and heating, together with the total decarbonization of electricity supply. Achieving the national target of net-zero greenhouse gas emissions by 2050 will depend on integrating large amounts of new renewable generation while phasing out fossil fuels for heating and transport. Currently, hydropower serves as Switzerland's primary source of system-level flexibility, and controlled electric boilers are the main tool for grid-level flexibility. However, heat pumps (HPs) and electric vehicles (EVs) are emerging as valuable sources of additional, complementary demand-side flexibility across both system and grid levels.

This report highlights the role of HPs and EVs as key flexibility enablers, supporting this transition through both system-level balancing and grid-level management. Flexibility from HPs and EVs is relevant because it enables shifting electricity consumption to align with renewable energy generation, reducing system costs, lowering electricity prices and imports, and lowering stress on electricity grids. In this way, electrification can proceed reliably and affordably within the Swiss net-zero pathway. Realizing the full potential of this flexibility requires technological advances, updated regulatory and policy, and improved market and operational mechanisms. Accordingly, the report first discusses flexibility potential at system and distribution grid levels, then examines EV and HP flexibility, followed by regulatory, policy, operational and market mechanisms, social acceptance, includes challenges and opportunities and concludes with recommendations to stakeholders.

At a glance: System-level potential of HP and EV flexibility in Switzerland by 2050*

Scenario-based model results; values are approximate best estimates (not forecasts). All changes are given relative to a "Both off" scenario with no HP or EV flexibility.

- Substantial shiftable load (5 TWh from HPs and 3 TWh from EVs)
- Additional renewable integration (+4% via avoided curtailment of PV and wind)
- Lower total system costs (HP only: -2%, EV only: -2%, combined: -4%)
- Lower net electricity imports (HP only: -12%, EV only: -10%, combined: -22%)
- Lower average wholesale electricity prices (HP only: -5%, EV only: -2%, combined: -7%)
- Less gas-fired capacity needed (HP only: -8%, EV only: -14%, combined: -31%)
- Less system-level battery capacity needed (HP only: -11%, EV only: -17%, combined: -33%)

** Results are scenario-based projections for Switzerland to 2050 – not forecasts – derived from system modelling using least-cost optimization under stated assumptions. Figures are indicative "best estimate" values, conditional on input data and methods, with uncertainty in technology uptake, prices, and regulation.*

The results and analysis presented in this report, unless otherwise specified, assume a continued agreement for electricity system integration with neighbouring countries ("CH-EU Stromabkommen" [1]) and align with the Swiss energy system plans for 2050 as presented in the recent Electricity Supply Act ("Mantelerlass Stromversorgungsgesetz"/"Energiegesetz" [2]), including, e.g., increasing support for flexibility aggregation, dynamic network tariffs, and data access. The focus of the research is on Switzerland, while energy trading with neighbouring countries is considered for the system-level analyses. Major changes in the regulatory and policy frameworks of the Swiss energy transition (e.g., Switzerland's discontinued integration into EU electricity and balancing markets through the CH-EU Stromabkommen[1]) would change the role of EV and HP flexibility and may make their contribution even more valuable in the long-term. Future research aims to explore those possibilities further.

Flexibility potential at system level

Scenario-based modelling results for 2050 show that HP and EV flexibility can support Switzerland to meet its goals for 45 TWh of non-hydro renewables and net-zero CO₂ emissions. However, large-scale electrification can introduce significant new demand. By 2050, estimates of annual Swiss electricity consumption range from 9 TWh to 17 TWh for HPs and from 11 TWh to 17 TWh for EVs, depending on modelling assumptions (see full report in section 3). Compared to an estimate of non-EV and non-HP annual consumption in Switzerland of 53 TWh in 2050, that means an additional electricity demand of at least 17% for HPs and at least 22% for EVs, while the total final energy demand falls.

If this demand is managed flexibly, the benefits are substantial. Simulations show that the system in 2050 makes good use of the available flexibility: 26% of Swiss HP demand (4.5 TWh) and 20% of Swiss EV demand (3.4 TWh) are shifted – a combined 8 TWh. For context, the contribution to shifted demand of batteries, net electricity imports, and pumped hydro generation were up to 1.0 TWh, 8.2 TWh, and 12.3 TWh, respectively, looking across the four scenarios studied.

Compared to a scenario with no EV or HP flexibility, HP flexibility can reduce net electricity imports by 12%, total system costs by 1.7%, and average wholesale prices by 4.9%; similarly, EV flexibility can reduce net electricity imports by 11%, total system costs by 2.1%, and average wholesale prices by 1.9%. However, with both types of flexibility combined we see even larger system benefits: nearly 4% more renewable generation through additional capacity and avoided curtailment, 22% lower net electricity imports, up to 4% lower total system costs, and around 7% reduced average wholesale prices, compared to the no flexibility case. In addition, combined EV and HP flexibility also reduce the need for investments in gas-fired plants (by up to 31%) and batteries (by up to 33%) compared to the system without EV or HP flexibility. These trends and positive system-level impacts are broadly confirmed by simulations with other electricity system models and scenarios [3].

Flexibility potential at distribution grid level

In the distribution level, the growing adoption of PVs, EVs, and HPs can stress Switzerland's low- and medium-voltage networks. Distribution networks in Switzerland are not dimensioned to handle very high shares of solar PV, EV charging, and HP unless flexibility measures are employed. Flexibility will be needed at the local level to reduce or defer costly grid reinforcements: transformer and cable upgrades due to overloads and/or voltage violations.

The analyses performed for over 50 MV and LV distribution grids show that flexibility through smart EV charging and HP control can reduce total required grid investments by a median of ~40% in urban areas, while limiting PV feed-in can reduce total grid investments by a median of ~40% in urban areas and ~ 50% in rural areas for 2040, with less than 3% annual energy loss when PV output is limited to the 70% of maximum production. These results underline the importance for utilities to implement flexibility-aware grid planning to manage peaks, and leverage local flexibility solutions [4; 5; 6; 7; 8; 9; 10; 11; 12; 13]. The median reductions are in relation to the investments that would be required by traditional planning methods when no flexibility measure is employed. It is noted that the results demonstrate maximum benefits based on the assumption that all HP, PV and EV charging infrastructure owners provide flexibility. In the meantime, it is important to emphasize that the level of uncertainty in estimating the available and reliable flexibilities is a significant challenge for the utilities.

Electric vehicle flexibility

Flexible EV charging is one solution to mitigate local congestions and integrate PV, particularly in urban areas with high adoption rates. The available flexibility varies with location and time and depends on technological and behavioural factors. Aligning EV charging with PV generation can reduce curtailment and enhance self-consumption, with workplace charging presenting an opportunity for demand shifting [14], as 40% of vehicles are parked near work or education locations during peak solar hours on weekdays [15]. Smart charging (V1G) and vehicle-to-grid (V2G) capabilities allow EVs to act as energy storage, shifting or discharging electricity to support the grid [16; 17]. V2G technology offers additional flexibility by allowing EVs to discharge energy back into the grid. V2G has the potential to reduce system-level PV curtailment even more than V1G by discharging ahead of high PV hours to make more space to charge and store more energy when PV production is high [18].

Heat pump flexibility

HPs offer flexibility in mitigating grid stress. HPs can be flexibly controlled to avoid peak loads (especially in winter), using thermal inertia of buildings and/or thermal energy storage (e.g., hot water tanks) to shift heating demand without losing comfort. Due to the high storage capacity of buildings, HP load can be curtailed for 2 to 10 hours at an outdoor temperature of 0°C maintaining comfort levels (up to 10 hours in renovated or new Minergie-level buildings) [19]. As a reference, an average HP can shift about 7 kW over a 2-hour curtailment (around 14 kWh) at 0°C. Scaled to all buildings in Kanton Zürich, this would correspond to around 1.7 GWh of shiftable load if every building were equipped with a HP.

However, if not properly coordinated, HP curtailments can lead to rebound effects causing sudden demand surges, which will need to be properly managed by grid operators [19]. A promising solution involves community-level approaches that coordinate the thermal inertia of multiple buildings or use HPs and PV to serve multiple buildings. This concept was tested in the pilot and demonstration project “nanoverbund”, which demonstrated its ability to enhance flexibility, reduce grid congestion and peak demand, and improve overall efficiency [20].

Regulatory and policy mechanisms

Regulations and policies for demand-side flexibility are shifting from supporting “simple” to “flexible” electrification [21]. However, gaps remain, particularly regarding accessibility and costs of EV and HP infrastructure and operation. To unlock system benefits, now that technology is ready, flexibility-ready regulation should make it easy to install, automate, better participate and benefit from offering their flexibility.

Despite setting national targets for decarbonisation, Switzerland's regulatory landscape is fragmented and flexibility-readiness is inconsistent across the country. For example, Switzerland lacks a nation-wide “right to charge” policy as well as binding requirements for compliance with smart charging and interoperability standards, creating barriers for tenants in e.g., multi-unit buildings who require charging access [21]. Some Swiss cantons provide subsidies for V1G and V2G chargers, but overall support remains inconsistent and prices sometimes prohibitively high (e.g., high station costs, tariff structures not yet aligned with flexibility needs, and double taxation on discharged energy) [18; 21]. Switzerland's DSO–supplier model offers advantages for direct load control, but coverage is still limited [21; 22]. In addition, the majority of suppliers do not offer dynamic tariffs at all as they are not mandated to, preventing end-users to offer their flexibility. Targeted policies, like new or updated dynamic tariffs, clear aggregator market access, opt-in direct load control, and other financing options, are needed to expand adoption.

Initiatives in cities like Basel, Lucerne, and Bern put this into practice demonstrating how local policies can drive flexibility solutions – the nanoverbund concept. The concept forms neighbourhood micro-heating networks (around multiple connected buildings) that demonstrate shared heat use, pooled flexibility, new utility revenue streams, and lower participation barriers [20; 23].

Operational and market mechanisms

Beyond policy support, well-functioning electricity markets are essential for integrating flexibility services. Flexible loads can be managed by a variety of actors, such as system operators, aggregators, energy suppliers, or prosumers, which control the same loads, requiring coordination and priority rules to avoid conflicting signals and grid / device violations.

Direct control of flexible loads by energy suppliers and aggregators can produce efficient results but faces implementation challenges related to privacy concerns, infrastructure costs, and consumer acceptance [21; 24]. The efficiency of dispatch in case of direct load control depends on how accurately the dispatch impact on the grid is taken into account and balanced against the dispatch impact on wholesale markets and balancing markets.

Dynamic prices can incentivize EV charging and HP operation at optimal times. They are less intrusive than direct load-control, but require regulatory updates that expand availability to consumers on top of social acceptance challenges [21]. Hybrid pricing models, combining dynamic volumetric and capacity-based pricing, are a solution to prevent over-coordination of automated loads and stabilize grid demand [25]. Additionally, profile contracts, in which consumers pre-agree on electricity consumption patterns, are a promising solution that can reduce price volatility while still incentivise flexibility participation [26]. Moreover, by bidding the aggregated flexibility of their flexible loads in day-ahead and intraday auctions, aggregators and energy suppliers can lower the electricity costs for their customers and improve system efficiency [27].

Social acceptance

Consumer acceptance is another critical factor in determining the success of flexibility initiatives. Surveys indicate that preferences vary significantly, with some consumers prioritizing cost savings while others value convenience and comfort [28]. Around 30% of Swiss consumers are willing to accept some level of comfort reduction to lower electricity costs, whereas 70% will only offer flexibility if it does not impact their comfort [28]. Furthermore, most consumers prefer direct load control of individual appliances over demand-response approaches that limit their total electricity usage [28]. Automation reduces aversion to price volatility by handling scheduling in the background, making dynamic time-of-use tariffs about as acceptable as static tariffs [29]. Opt-out (default) enrolment boosts participation compared with opt-in designs [30]. Comfort can be preserved through device limits with easy user override (e.g., minimum EV state-of-charge, indoor temperature bands). Contract menus (e.g., flat-rate with automatic direct load control, or time-of-use for non-automated users) can accommodate different preferences and prevent rebound peaks [31]. Finally, profile contracts can hedge bill volatility while keeping incentives for load shifting and reductions, improving acceptability for risk-averse households [26; 32].

Recognizing these preferences is crucial for designing effective flexibility programs, as surveys reveal that the Swiss public generally supports flexible EV charging and HP integration [33].

Challenges and opportunities

Unlocking the full potential of flexibility from HPs and EVs still faces several obstacles. On the technical side, Switzerland's distribution grids are not dimensioned for widespread electrification, leading to risks of local congestion and costly reinforcements. Policy gaps persist, such as the absence of a nationwide "right to charge" compliant with smart charging standards, slow adoption of dynamic tariff structures, and inconsistent support for flexibility-ready (i.e., automated, controllable) infrastructure. High upfront investment costs for EVs and HPs, along with consumer concerns over comfort and convenience, further limit adoption of flexibility.

To address these barriers, demand-side flexibility solutions are: (1) V1G and, where cost-effective, V2G strategies; (2) controlled HP operation that exploits buildings' thermal inertia, thermal storage, and shared heating networks; (3) flexibility-ready regulation that makes it easy for end-users, operators, and aggregators to participate and offer their flexibility; (4) dynamic or hybrid tariff models that reward flexibility; and (5) expanded market access for aggregators to integrate flexibility services into wholesale and balancing markets. Adopting flexibility-aware distribution grid planning frameworks enables utilities to identify cost-effective flexibility options that defer or reduce grid infrastructure investments. Together, these solutions can help Switzerland to accelerate the proliferation of EVs and HPs to reach its decarbonization targets, integrate them seamlessly into distribution grids, and enable additional services to upper grid levels, while providing benefits for consumers and utilities.

Summary and future work

The full report highlights the contributions of HP and EV flexibility, identifies the main challenges to their integration, and outlines possible solutions and stakeholder actions. Stakeholders across Switzerland including policymakers, electricity system operators, EV and HP providers, flexibility aggregators, cantons, municipalities, and end-users can all draw on the PATHFNDR research presented in this

report to better understand the value of EV and HP flexibility, the barriers to its adoption, and the next steps needed to unlock its full potential in Switzerland.

Future work should focus on deepening the understanding of EV and HP flexibility synergies, adoption barriers, user behaviour, and real-life implementation to support scalable integration into Switzerland's energy system.

Recommendations to stakeholders

- **Federal government:** Enable flexibility-readiness by supporting combined electric vehicle and heat pump adoption, mandating nationwide “right to charge,” requiring flexibility-ready controls, smart charging standards, and mandating suppliers to offer dynamic tariffs, and aligning market rules to allow actors to participate in flexibility services, reducing system costs, lowering net electricity imports, and supporting renewable integration.
- **Canton and municipality:** Promote local flexibility by providing incentives for controllable heat pumps, shared thermal networks, and smart electric vehicle charging (V1G/V2G) to scale participation, reduce grid stress and unlock new revenue streams for end-users.
- **Transmission system operator:** Coordinate with distribution system operators to ensure flexible resources can support both system balancing and local grid management, reduce costs, and improve grid stability.
- **Distribution system operator / utility:** Ensure that the grid models for low voltage networks (i.e., network layer 7) are available for grid simulations, which will enable effective adoption of flexibility-aware grid infrastructure planning frameworks that leverage end-user flexibility to defer and reduce the need for distribution grid upgrades by (i) shifting and/or reducing the load due to HPs and EV charging, (ii) limiting the PV feed-in, and (iii) taking into account the voltage support provided by PVs.
- **Aggregator and energy supplier:** Scale dynamic and hybrid tariffs with default opt-out, automation, appliance-level direct load control, and risk-hedging contracts to boost end-user participation while enabling aggregators to reduce procurement risks, access new revenue streams, and build scalable business models.
- **Technology provider and manufacturer:** Deliver flexibility-ready devices with open standards (e.g., SmartGridready), control automation, and measurement interfaces to enable flexible, grid-friendly operation, expand market access, facilitate interoperability, and increase the value of devices through participation in flexibility services.

The full report presents detailed recommendations tailored to each stakeholder group.

Abstract

Switzerland's energy transition relies on electrifying transportation and heating while keeping electricity generation low in greenhouse gas emissions and ensuring grid stability. The required energy system flexibility will still be provided mainly by hydropower. However, additional valuable demand-side flexibility could be provided by electric vehicles and heat pumps by shifting their consumption to align with renewable energy generation. This report evaluates the role of electric vehicle and heat pump flexibility by synthesizing research from across the PATHFINDER project consortium. The report thus quantifies these technologies' potential flexibility and value in supporting both the transmission and distribution systems and assesses existing and required market and policy mechanisms to unlock their full benefits.

New scenario-based modelling results show that flexibility provision from electric vehicles and heat pumps can reduce system costs, defer network upgrade investments, lower electricity prices and imports, and reduce curtailment of renewable energy by better aligning demand with surplus generation. Electric vehicle smart charging and vehicle-to-grid can act as energy storage, which shift or discharge electricity to support the grid. Heat pump demand can be shifted using thermal inertia and thermal energy storage to reduce peak demand and stabilize the grid. At distribution level, flexibility-aware planning can reduce or defer low- and medium-voltage grid upgrades with minimal PV energy loss.

Our research also finds that enabling flexibility-readiness through supportive policy and market mechanisms are critical for effective demand-side management. Some mechanisms are already in place, such as contracts with dynamic pricing, direct load control, and subsidies for smart charging and vehicle-to-grid infrastructure. However, further policies, changes to regulation, and owner/user acceptance are needed. Surveys of the Swiss public show that support for flexible EV charging and heat pump operation is high, indicating readiness for further policy and market changes supporting flexibility and renewable energy integration.

Unlocking this flexibility will improve Switzerland's energy resilience and sustainability while empowering consumers to participate actively in grid management. Future research should focus on scalable implementation and deployment: exploring business models for flexibility provision, evaluating new policy incentives, and demonstrating the use of flexibility at scale.

1 Introduction

To achieve net-zero greenhouse gas emissions, every energy demand sector is undergoing a major transition. Transportation and buildings are two of the highest emitting sectors, together accounting for over 55% of emissions in Switzerland in 2022 [34]. Increasing energy efficiency and increasing the use of renewable energy are two pillars of the Swiss Energy Strategy 2050 [35]. Electrification has also emerged as a key pathway to decarbonize transportation and heating by leveraging low-carbon energy from the electricity system. Battery electric vehicles (EVs) and heat pumps (HPs) now play a central role in Swiss and global plans to reduce emissions [2; 36; 37].

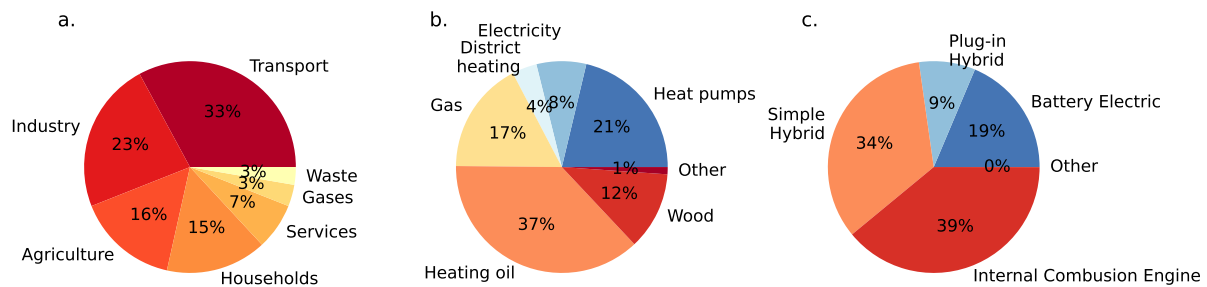


Figure 1.1: (a) Percentage of Swiss total domestic greenhouse gas emissions by sector in 2022, measured in CO₂ equivalent [34], (b) percentage of Swiss households using each heating technology in 2023 [38], and (c) percentage of Swiss passenger vehicle sales by technology in 2024 [39]. Each subplot uses the most recent data available at the time of writing. This figure illustrates the importance of tackling transport and household emissions and shows Switzerland's progress so far in the transition to electrification.

The role of EVs and HPs as key pathways to decarbonize transportation and heating is widely demonstrated in the literature, with numerous studies highlighting the potential to reduce system costs arising from the flexibility they provide to the energy system [40; 14; 41; 42; 43; 44]. In addition, HPs are consistently identified as an effective option to reduce emissions at the local level, reflecting their high efficiency, low emissions, and flexibility to variable electricity prices. We also find that HPs are consistently selected to reduce emissions at the local level [45], reflecting their high efficiency, low emissions, and flexibility in the face of variable electricity prices.

Still, despite the advantages of electrification in the transportation and building sectors for decarbonisation, EVs and HPs face barriers to deployment related to high costs, supply chain development, and consumer preferences [46; 47; 48]. Sales growth for both EVs and HPs slowed in 2024 due in part to tightening household budgets [39; 49; 50], but the transition is expected to continue in the coming years thanks to clear policy support, e.g., [51], and improvements in economic and technical performance. EV operating costs are typically lower than for a comparable internal combustion engine vehicle and upfront purchase prices are approaching parity [37]. Similarly, HPs typically have lower operating costs than comparable gas boilers. Over their lifetime, these operational savings can outweigh HPs' high upfront purchase prices in some markets, with the added benefit of mitigating

the risk of spikes in fossil fuel prices [36; 48]. Benefits from HP systems could be increased with better sizing and application-specific configuration [52]. From an emissions perspective, EVs have > 70% lower life-cycle emissions than petrol combustion engine vehicles and HPs have > 88% lower emissions than fossil fuel boilers in Switzerland thanks to the grid's low average carbon intensity [53].

Policymakers recognized the need for EVs and HPs early and a widespread network of policy support has been key to these cost reductions and early deployments [54; 55]. A systematic review of incentives for EVs and HPs in Switzerland and its neighbors found 22 distinct types of policy instruments, including roadmaps, targets for the number of EVs, chargers, and HP installations, purchase subsidies, tax credits, leasing or loan programmes, CO₂ pricing, direct government investment, building efficiency requirements and bans on competing emitting technologies [21]. On the EV side, incentives for EV purchases have been found to also impact supply-side developments and innovation activities; without demand-side support policies, the R&D expenditures on EVs of automakers may decrease and delay the transition to EVs [56]. On the buildings side, an optimal policy mix for cost-efficient decarbonization combines HP subsidies with building retrofit incentives, with retrofits implemented at the same time or before HPs incentives to prevent oversizing [45]. Without targeted HP subsidies or other supports like a carbon tax, fossil fuel boilers like gas or oil may remain more cost-effective (or be perceived to be more cost-effective), slowing decarbonization efforts in the Swiss building sector [45; 57].

Innovative business models, product design, and new strategies focusing on reputation have also played an important role. Researchers have found that companies' product and reputational strategies are key to earning customer approval in the market for new EVs [58]. Car companies must develop strategies to build a positive reputation that can turn customers into active advocates for the brand, recommending it to their friends and family. Car companies can also benefit from strategic planning to anticipate future policy developments, drive technological developments, and build a set of complementary products like rooftop PV or home battery storage to sell alongside their cars [58]. Major EV manufacturers have seen growing success from adopting these strategies.

As a result of all these factors, EV and HP adoption are off to a strong start. In Switzerland, passenger EVs in total hit 30% of sales (21% fully electric and 9% plug-in hybrid) and 4.9% of vehicle stock (3.3% fully electric and 1.6% plug-in hybrid) in 2023, before dropping slightly to the numbers shown in Figure 1.1c [39; 59]. Recent research finds that many firms are heading toward electrification for future medium-duty trucks in urban areas. There is some momentum for heavy-duty trucks in Switzerland, too, driven by improving technologies, policy support, and shifting societal values; however, ongoing discussions about regulatory changes and the need for large infrastructure investments introduce some uncertainty and prevent logistics firms from fully committing to electrification [60]. On the heating side, as shown in Figure 1.1b, HPs now account for 21% of household heating technologies across Switzerland, but 66% of households still heat with oil, gas, or wood [38]. HP adoption must accelerate for Switzerland to reach its net-zero target by 2050.

Alongside these trends in electrification, the energy system transition to decarbonize electricity supply by increasing deployment of renewable resources, including more intermittent generation from wind and solar, brings challenges to the planning and operation of the electricity transmission and distribution systems. EVs and HPs increase the consumption of electricity, potentially resulting in power flows that go beyond today's electricity network capacities [61]. As wind and solar cannot follow demand, more flexibility is needed at the system level to avoid potential imbalances between electricity supply and demand.

It would be very costly to address these challenges solely through investments in electricity networks, e.g., to increase their power transfer capacities, and difficult to address solely through investments in dispatchable, flexible power generation or storage resources to produce or shift electricity to times of wind and solar deficit [62]. Hence, as a complement to these conventional approaches, a paradigm shift is underway in how power systems are operated: from a mode of operation where generation always follows demand to a mode where, to the extent possible, demand follows the available generation.

Put more simply: we need to engage the flexibility in electricity demand, including from new technologies like EVs and HPs, so that electricity is preferentially consumed when the wind is blowing and the sun is shining and in a coordinated way that does not congest or otherwise damage the network.

The exact value and potential of demand-side flexibility for a successful Swiss energy transition is not yet fully clear. How flexible can these demand resources be? Is their flexibility potential substantial enough to make a real difference to the cost of the energy transition? How can this flexibility be tapped into in practice?

HPs and EVs are key potential sources of demand-side flexibility. EVs serve primarily for transportation, but their charging represents a form of mobile energy storage. Controlled charging (V1G), also called smart charging, shifts the timing of EVs' electricity consumption; vehicle-to-grid (V2G), also called bi-directional controlled charging, extends controlled charging to allow discharging back from the V2G. V1G and V2G have many potential benefits: for example, V1G can shift demand to avoid peak periods or absorb excess PV generation; and V2G can help with balancing by injecting stored energy to the grid during periods of high demand or by increasing local self-consumption [63]. HPs can flexibly adjust their load and reduce stress on the grid during peak demand or cold waves, leveraging thermal energy stored in buffer storage tanks and the thermal inertia of buildings, and by implementing advanced control strategies to manage energy consumption while maintaining thermal comfort. Using flexible HP operation combined with (seasonal) thermal energy storage can enhance energy efficiency, increase self-consumption and support renewable integration [36].

In this report, we will synthesize our understanding – to the best of our knowledge based on the latest research – of how EVs and HPs will interact with the electricity system, how their flexibility could be used to support the electricity system's transition, and how that flexibility should be unlocked with different policy and regulatory tools.

2 What is flexibility from EVs and HPs used for?

First, we present scenario-based results for Switzerland's energy system to 2050 to identify how EV and HP flexibility are used at the transmission system and distribution system levels. These results are projections, not forecasts or predictions. They arise from empirical data and system modelling using least-cost optimization under stated assumptions. Results depend on input data, socio-economic and technological assumptions, and methodological choices. They should therefore be interpreted as indicative "best estimate" values rather than precise figures, given uncertainties in technology uptake, prices, and regulation. The authors are responsible for the analysis and its interpretation.

2.1 System-level perspective

As we move toward a future where variable generation resources dominate the electricity supply, flexibility is critical to balance supply and demand. At the system level or from the transmission system operator perspective, we find that EV and HP flexibility provide many benefits to the system: reducing curtailment of renewable generation, reducing the need for investment in other sources of flexibility, and reducing Swiss system costs and average electricity prices. In this section, we briefly detail the methodology and scenarios used for this analysis, then provide detailed results for each of these impacts.

The assumptions underlining the presented scenarios are consistent with CROSS-scenarios [64]. Here by system-level we refer to the bulk power system (network level 1), including trading with neighbouring countries.

We use a soft coupling between the Nexus-e and Euro-Calliope energy system models, representing an early-stage implementation of a broader soft-linking framework that will also incorporate SecMOD. The joint modelling approach seeks the lowest energy system cost for 2050, by minimizing investments in energy generation, storage, and transmission capacities, while optimizing hourly operations to meet energy demand [65]. Following current Swiss regulations, we implement a binding target that forces the model to supply 45 TWh of electricity generation from non-hydro renewables (solar, wind, and biomass) by 2050 [2]. Based on the current regulations, this target includes renewables curtailment. We also include a European-wide net zero CO₂ target for the entire energy system and a Swiss-specific net-zero CO₂ target for its energy system. Euro-Calliope models all energy sectors, including electricity, heat, transport and liquid fuels, in all of Europe with a country-level spatial resolution. Nexus-e then provides a detailed, high-resolution model of the Swiss electricity system only, using outputs from Euro-Calliope to represent other energy sectors and as boundary conditions for imports and exports outside of Switzerland. Ongoing work in the PATHFINDER project aims to connect Nexus-e

and Euro-Calliope with a third model, SecMOD; the results presented here may change when run with the final modelling suite. We assume high energy market integration, meaning the Swiss energy system is well-integrated in the European electricity system with coordinated electricity trade and no restrictions on energy commodity exchanges (i.e., EU-CH Stromabkommen / electricity agreement[1]), and use detailed representations of EV and HP demand and flexibility.

The model of EV demand in Nexus-e combines detailed data on individual driving patterns, a model of vehicle energy consumption, and scenarios of charging infrastructure availability to simulate charging across Switzerland [15; 66]. We define an uncontrolled scenario and a controlled scenario for EV charging demand. The uncontrolled scenario assumes vehicles charge immediately upon arrival at a charging station, charging at the maximum charging rate until the battery is full or the vehicle leaves the station. The controlled scenario is optimized by the model, subject to constraints that ensure charging can only occur within existing plug-in sessions and that each vehicle ends each parking session with the same battery state-of-charge as in the uncontrolled scenario. This approach ensures the use of EV demand flexibility does not impact the experience of the vehicle owners: they are not required to change their mobility or plug-in behaviours, and they always receive the same amount of energy. The model of HPs in Nexus-e uses data about the thermal characteristics of individual buildings, scenarios of the building stock evolution, and a distribution of HP specifications to simulate future electricity demand for residential space heating across Switzerland [67]. Bounds are defined to constrain the shifting of HP demand so that temperatures stay within an acceptable range for building occupants, given the physical characteristics of each building. We make the assumption that only 33% of HPs are controllable, matching the total load shifted to recent conservative HP modelling [22]. In total, this approach ensures the comfort of building occupants, and a further fraction of HP demand is assumed to be fully inflexible.

The HP and EV flexibilities are both made available to the Nexus-e central optimizer at no cost. This approach combines conservative assumptions about the impacts of flexibility on individuals and the availability of flexibility technologies (limited participation in HP flexibility and no bidirectional charging capabilities) with optimistic assumptions about the system's knowledge and access to flexibility. Future work aims to test the impact of adding implementation costs for EV and HP flexibility and varying participation rates.

To test the use and benefits of HP versus EV flexibility at the Swiss level, we compare the following four scenarios shown in Table 2.1.

Euro-Calliope models the optimal adoption of each technology. At the European level, the model shows that increasing the flexibility of EVs and HPs supports the electrification of both the transport and heating sectors. These flexibility measures reduce reliance on expensive combined heat and power (CHP) peaker plants. As CHP plants are phased out, the model compensates by increasing HP deployment to meet heating demand.

In Switzerland, however, HP penetration remains constant at approximately 75% in the high market integration scenarios. This is because the country benefits from dispatchable renewable resources such as hydro and cost-effective storage through pumped hydro plants, which reduce the need for CHP expansion. As a result, HP flexibility primarily affects the deployment of heat storage technologies rather than the overall heating mix. The model chooses an EV penetration of 100% across all scenarios with EV flexibility. In the "HP only" and "Both off" scenarios, limited EV charging flexibility leads to increased use of pumped hydro to meet inflexible EV charging load, and a 5–6%

rise in net electricity imports compared to scenarios with EV flexibility. Additionally, the lack of EV flexibility results in an increase in electricity curtailment. To further manage these constraints, the system shifts a portion of passenger vehicles, around 2%, to fuel cell electric vehicles (FCEVs), in contrast to a fully electrified transport sector in scenarios with EV flexibility. This shift is driven by the greater operational flexibility of electrolyzers compared to inflexible EV charging.

Nexus-e does not model technology adoption, but gives a more detailed simulation of the Swiss electricity system. To isolate the effect of Swiss flexibility decisions, we use the Euro-Calliope “Both off” scenario results as inputs for all four Swiss Nexus-e scenarios.

Key Assumptions for the Euro-Calliope–Nexus-e Analysis

- A European-wide CO₂ target of –200 Mt for the entire energy system and a Swiss-specific net-zero CO₂ upper bound for its national energy system. Each modelled country is allowed to compensate for CO₂ emissions abroad.
- Europe can freely trade hydrogen, hydrogen-based fuels, and biomass-based fuels among the modelled countries. The continent is assumed to be self-sufficient, with no imports or exports to or from regions outside Europe. At European level, distribution grids are not represented, and the transmission grid is aggregated at the NUTS 0 level to match the national resolution.
- High energy market integration, i.e. coordinated electricity trade with EU countries and no restrictions on energy commodity exchanges (EU-CH Stromabkommen[1]). *Sensitivity tested with low net transfer capacity (NTC) scenarios.
- Constraint requiring 45 TWh non-hydro renewables generation potential (including curtailment) in 2050 [2]. *Sensitivity tested in Wang et al. [3].
- Perfect foresight within the year and fully deterministic.
- No demand elasticity and fully rational (price-based) decision-making of all agents.
- EV and HP flexibility in Switzerland per the following scenarios:

Scenario Definitions

		EV Flex	
		ON	OFF
HP Flex	ON	① “Both on”	② “HP only”
	OFF	③ “EV only”	④ “Both off”

Table 2.1: Matrix illustrating the four main scenario definitions.

Diving into the Nexus-e simulation results for the Swiss system, we see that the system makes use of the available flexibility and large amounts of energy are shifted in each case. 26% of Swiss HP demand (4.5 TWh) and 20% of Swiss EV demand (3.4 TWh) are shifted in the “HP only” and “EV only” scenarios. For context, across the four scenarios batteries discharged between 0.6 and 1.0 TWh, annual net electricity imports were between 6.4 and 8.2 TWh, pumped hydro provided between 11.5 and 12.3 TWh, and total annual electricity demand was 87 TWh.

An important difference between the two sources of flexibility is in how they change throughout the year. EV energy consumption can vary by up to 16% between the warmest and coldest days of the year [15]. HP energy consumption is much more seasonal, predominantly concentrated in the winter. The Swiss electricity system is most stressed in the winter when it depends more on imports from neighbouring countries. In those critical hours, HP flexibility is well timed to help. EV flexibility can help the system more consistently year round, including during summer hours with peak curtailment of PV generation. These seasonal differences and opportunities are reflected in the following results.

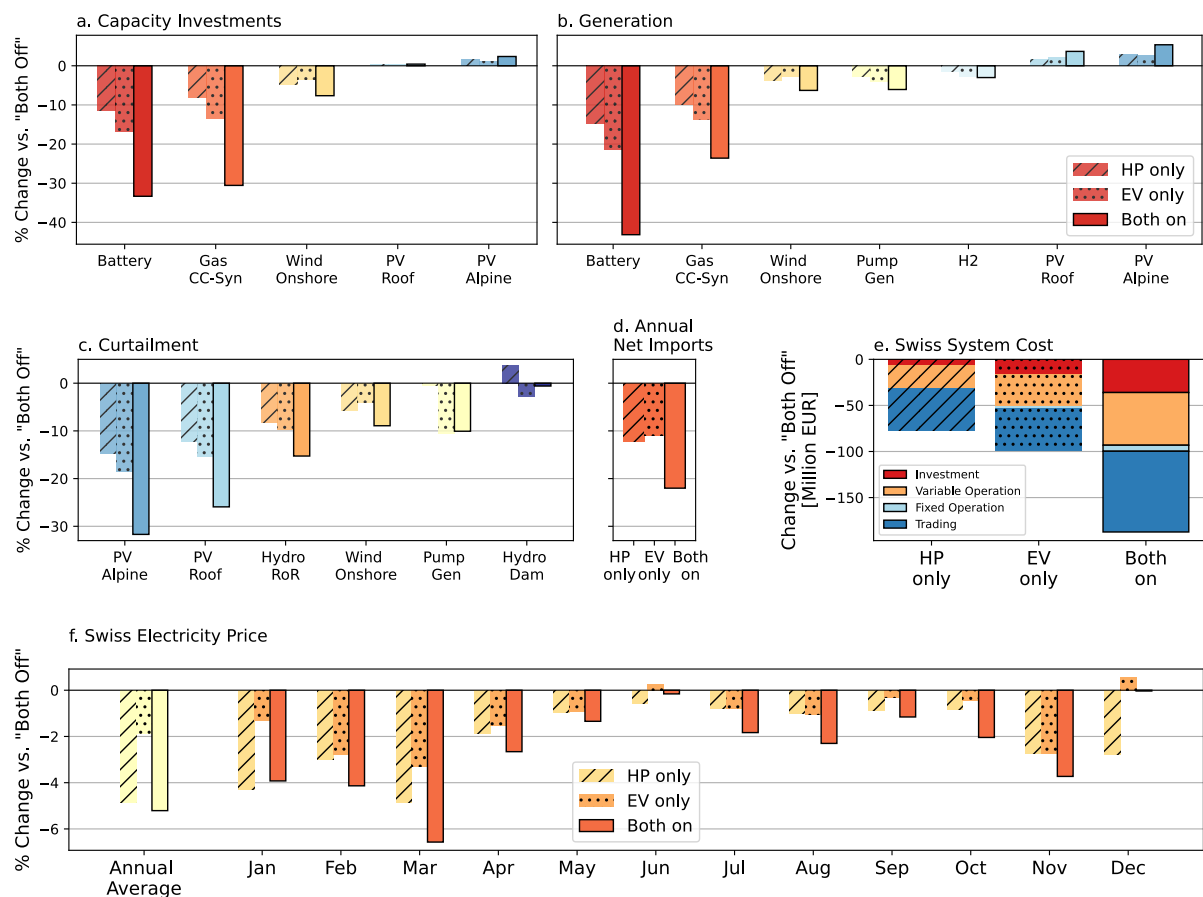


Figure 2.1: System-level comparison of (a) capacity investments, (b) electricity generation, (c) curtailment, (d) annual net imports, (e) system costs, and (f) average electricity prices between scenarios with only EV flexibility (dots), only HP flexibility (slashes), or both EV and HP flexibility (solid). We do not plot technologies for which the changes were very small. All values are with reference to the “Both off” scenario with no EV or HP flexibility in Switzerland. The colours in (d-f) are not connected to particular technologies and blue/red do not indicate good/bad. The total system costs are reduced by 1.7%, 2.1%, and 4.0% in the “HP only”, “EV only”, and “Both on” cases, respectively, compared to the “Both off” case. The costs are annualized for the year 2050 only. This figure illustrates the wide range of system-level benefits from EV and HP flexibility.

First, we see that EV and HP flexibility is used to support the integration of renewable electricity sources. The 45 TWh renewables target in 2050 means that the same total amount of renewable electricity potential must be built in all scenarios, but flexibility is used to reduce curtailments and costs by making better use of those resources; both the “EV only” and “HP only” cases reduce investments and generation in wind capacity and increase investments and generation in rooftop and alpine PV. Rooftop PV is the largest absolute contributor to the increase in renewable generation, with most of the increase occurring in the spring and summer. As shown in Figure 2.1, both cases also substantially reduce curtailments of PV and wind while also reducing curtailments (water spillage) of hydro pumped storage, dams, and run of river. Compared to the “Both off” case, the “EV only” flexibility reduces curtailments by more than “HP only” flexibility in all cases except wind, as the seasonality of HP demand is better aligned with wind production.

Second, we see an impact on the use of dispatchable generators and other sources of flexibility. Both EV and HP flexibility reduce the need for investments in grid-scale battery storage and gas-fired power plants, and reduce the use of fuel cells and pumped hydro storage. Relative to the capacities and generation in the “Both off” scenario, the “Both on” scenario achieves a 33% reduction in the installed capacity (100 MW less power capacity and 400 MWh less energy capacity) and a 43% reduction (0.49 TWh) in electricity used from battery storage. We see that the “EV only” case has a larger relative impact on reducing gas and hydrogen fueled generation because it has a higher capacity for downshifting the flexible demand during critical winter hours.

Trade with neighbouring countries is another important form of flexibility. Again, the system needs this source of flexibility less as both EV and HP flexibility reduce Switzerland’s dependence on trade. Here HP flexibility has a slightly larger impact because the most important exports and most critical imports occur during the winter and HP demand is winter focused. Annual net imports are reduced by 11% and 12% in the “EV only” and “HP only” cases, respectively. These changes in net imports are the combination of a decrease in net imports during winter months and an increase in net exports during summer months.

Third, we see substantial impacts across scenarios on prices and system cost. Costs for the Swiss electricity system are reduced by 2.1% and 1.7% in the “EV only” and “HP only” scenarios, compared to the “Both off” scenario. Most of these savings come from reducing costs for electricity imports, increasing revenues from electricity exports to neighbouring countries, and reducing operating and investment costs for gas units, fuel cells, and batteries. As shown in Figure 2.1, EV and HP flexibility have similar cost benefits in terms of imports and exports, but EV flexibility has a larger impact on savings through displacing investment and operating costs from other flexibility technologies in Switzerland.

These impacts on system costs also translate to electricity prices. Both EV and HP flexibility reduce the annual average wholesale electricity price in Switzerland and, to a lesser extent, in neighbouring countries. Compared to the “Both off” scenario, the “HP only” case reduces the annual average price in Switzerland by more than the “EV only” case, 4.9% vs. 1.9%, due to its winter focus. This is reflected in the impact on monthly average Swiss prices as shown in Figure 2.1.

Surprisingly, benefits in the “Both on” scenario are close to the sum of benefits from the “EV only” and “HP only” scenarios. Separately, EV and HP flexibility increase renewable generation by 2.2% and 1.9% relative to the “Both off” base case; together in the “Both on” case, they achieve a 3.8% increase. Similarly, relative to the “Both off” case, annual average electricity prices in Switzerland decrease

by 1.9% and 4.9% with EV or HP flexibility separately, but 5.2% with both flexibilities combined. Compared to the "Both off" case, annual net electricity imports to Switzerland decrease by 22% in the "Both on" case, compared to 11% and 12% with "EV only" or "HP only" flexibility. This 22% reduction is caused by decreasing net imports in winter months (0.69 TWh less across October-April, a change of -4%) and increasing net exports in summer months (1.11 TWh more across May-September, a change of +14%).

In some metrics, "Both on" benefits even surpass the sum of benefits in the other two scenarios, suggesting synergies between the two sources of flexibility. Separately, EV and HP flexibility decrease investments in battery capacity by 17% and 11% and decrease investments in gas-fired generation capacity by 14% and 8%, compared to the "Both off" scenario; together in the "Both on" case, they decrease investments in batteries by 33% and in gas-fired generation capacity by 31%. Separately, EV and HP flexibility reduce Swiss total system costs by 2.1% and 1.7% compared to the "Both off" scenario; together in the "Both on" case they reach a 4.0% reduction. This result also suggests the system is not saturated with flexibility, as the system uses and benefits from each addition of flexibility without strong diminishing returns. Understanding these synergies will be an important area of future research.

In summary, both options for flexibility bring economic and system benefits, decreasing prices and system costs, supporting the integration of renewables, and reducing the need for other flexibility options. The benefits from EV and HP flexibility are of the same order of magnitude. Importantly, the benefits of EV and HP flexibility do not cancel each other out. Instead, the results suggest synergies and complementarity between the two flexibility sources that should be further investigated.

These results may vary under alternative assumptions about Switzerland's market integration with Europe. If Swiss integration with neighbouring markets decreases, e.g., following a future referendum on the CH-EU Stromabkommen[1], the role of flexibility in the system will change and may make its contribution even more valuable in the long-term [68]. To explore this, the same set of flexibility scenarios is assessed under more constrained conditions: cross-border electricity exchange is limited to 30% of high integration levels, and imports of hydrogen and methane are reduced. Under these constraints, the "EV off" and "Both off" scenarios show increased net electricity imports and curtailment, along with a doubling of CHP deployment in the Euro-Calliope simulation results. Table 2.2 dives into a comparison of the low and high integration cases using results from the Nexus-e simulation. We see that total system costs are higher in the scenarios with lower integration, and the value of flexibility is higher, too. Future research will further explore such scenarios to better understand the role of EV and HP flexibility under different system conditions.

Further PATHFINDER research using the EXPANSE electricity system model has also explored these scenarios and sheds light on the system-level value of EV and HP flexibility in Switzerland in 2050 [3]. The EXPANSE study uses a spatially detailed model of EV and HP demand in 2136 municipalities across Switzerland. Flexible EV and HP demand is dispatched as part of the system optimization. Beyond the unidirectional (V1G) flexibility from EVs in the previous analysis (above and in [14]), this study also considers bidirectional charging (V2G) and HP flexibility. Additional scenarios compare the impact of the 45 TWh renewables target to further investigate the connection between demand flexibility and renewables integration.

	High NTC			Low NTC		
	Both Off	Both On	Change	Both Off	Both On	Change
2050 System Costs [Bn EUR]	4.7	4.5	-4%	5.5	5.2	-5%
Net Electricity Imports [TWh]	8.2	6.4	-22%	9.8	8.6	-12%
Total Curtailments [TWh]	7.8	6.2	-21%	17.8	18.8	+6%
Annual Avg Elec Price [EUR/MWh]	52	49	-5%	162	153	-6%
Renewable Generation [TWh]	37.5	39.0	+4%	38.0	39.2	+3%
Battery Capacity [GW]	0.3	0.2	-33%	0.8	0.2	-75%

Table 2.2: Comparison of select key metrics between the scenarios with high and low net transfer capacities (NTC), representing high and low system integration with neighbouring countries. With the low NTC we also see higher investments in alpine PV, wind generation, and P2G2P, which contribute to the higher costs. Though net imports are higher in the low NTC cases, absolute imports are much lower than in the high NTC cases (approximately 32 vs. 61 TWh). We also see that system cost savings from EV and HP flexibility in the low NTC case are mostly thanks to lower investment costs. Note: renewable generation includes generation from PV and onshore wind.

The findings confirm that EV and HP flexibility reduce the use of other storage options and reduce investments in batteries [3]. They also confirm that turning on EV and HP flexibility leads to increased PV generation and lower PV curtailment, which corresponds with lower investments in wind generation. The 45 TWh renewables target and scenarios with restricted trading with neighbouring countries (lower net transfer capacity) both reduce Switzerland's net electricity imports, and turning on EV and HP flexibility reduces them even further. On the other hand, the results show no impact on gas investments and only small impacts on the use of pumped hydro storage, whose use in the model as seasonal storage cannot be replaced by EV and HP flexibility which is limited by shorter time windows for shifting. Constraints on timing and shifting also limit the ability of HPs alone to promote PV generation; the results find that HPs have a smaller system-level impact than EVs overall, especially when considering V2G. The constraint of a 45 TWh renewables target has a substantial impact on the value of EV and HP flexibility [3]. Scenarios with this target are forced to build very high amounts of renewable generation, with or without EV and HP flexibility. Flexibility can have a bigger impact on PV generation in scenarios where the target for renewables is not enforced.

In sum, these results point to clear system-level benefits from demand flexibility. They also point to the importance of the various modelling assumptions and boundary conditions: in particular, Switzerland's electricity system integration with neighbouring countries and Switzerland's targets for domestic renewable generation will shape the future electricity system.

2.2 Distribution-level perspective

In short

- There are ~ 630 electric utilities in Switzerland serving urban, rural, and mixed regions. The heterogeneity is so high that generalization of benefits of various flexibilities is not possible.
- Analysis of 50+ Swiss MV and LV distribution grids show that limiting solar PV feed-in is the most effective measure.
- Incentivizing the flexible demand shift to peak PV hours (especially in summer) and/or night time is effective (i) to manage the PV feed-in while increasing self-sufficiency and (ii) to decrease the evening peak demand.

While the system-level benefits of EV and HP flexibilities are observed mainly in balancing supply and demand, the distribution network-level benefits are mainly in managing local network congestion (e.g., overloading of cables, transformers) to mitigate the need for network reinforcement. The importance of using the flexibilities by new demand such as EV charging, flexible HP operation and PV curtailment for planning have been recently reported [69; 70; 71; 72] with methodologies developed for long-term grid planning [4; 5; 6; 7; 9; 10; 11; 73; 74; 75; 76; 77] and real-time control of such resources [8; 78]. As part of PATHFNDR, we developed an electricity distribution network planning framework for future scenarios, considering the possibility that the utility receives flexibility services from its end-customers. The framework is described in detail in the project deliverable [12] and relies on (i) solving the non-linear AC power flow equations and (ii) performing optimal dispatch of the available flexibility resources in an iterative manner.

Figure 2.2 serves only as an illustration of the how the developed flexibility-aware distribution planning framework [12] for a selected part of a utility's MV distribution network can be used to defer or reduce the need for grid investments. The planning horizon is for three target years: 2030, 2035 and 2040. The assumed penetration levels of PVs, EVs and HPs, per target year, are selected according to the latest regulation on Swiss energy strategy targets (i.e., Mantelerlass Stromversorgungsgesetz/Energiegesetz) [2]. Two parameters are varied: (i) flexibility from PVs by means of curtailment, and (ii) flexibility from HPs and EV by means of shifting their consumption. The network diagrams in the figure show, per cable, how many additional identical cables would be needed at which target year, to ensure that there are no network violations (i.e., overloading of cables, overvoltages). In this contained example it is observed that the network reinforcements can be fully avoided by using a combination of flexibility from PVs, HPs and EVs. The algorithm developed makes it possible to identify the value of flexibility, expressed as network reinforcement savings. It is noted that within the scope of this study, impacts of using grid-friendly (e.g., delayed charging to reduce the peak PV injection) residential BESS on the grid investments are not investigated, however, the results by using PV curtailment as a flexibility measure are indicators of the benefits of using grid-friendly residential BESS operated with the residential PV systems.

In order to analyze a larger set of real grids the methodology is optimized for computational efficiency and applied to a set of real rural, mixed (e.g., semi-urban, semi-rural) and urban Swiss distribution

networks (more than 50 distribution networks encompassing MV and LV grids in different parts of Switzerland, serving roughly 300'000 buildings in total). It is important to note that these networks are not necessarily representative of all distribution networks in Switzerland, but analyzing them allows to draw conclusions. Assumptions used in the analysis are based on [77] and [13]. This report is dedicated to the results only due to space considerations. It is assumed that all PV, HP and EV owners provide flexibility and therefore the results demonstrate maximum benefits. The investment costs (CAPEX) and the operational costs (OPEX) are included for all grid components along with the digging costs for cable upgrades and the building costs for transformer upgrades.

Figure 2.3 shows, for the selected set of Swiss grids, the required network upgrade investments according to traditional grid planning practices without using the flexibility potential of the distributed resources, for a proliferation scenario in 2040 corresponding to the objectives of Mantelerlass Stromversorgungsgesetz/Energiegesetz[2]. The ratio of the installed PV capacity in 2030, 2035 and 2040 to the maximum demand today is used as an indicator (x-axis) to illustrate the magnitude of paradigm shift. Note that the results show the diversity of the selected networks in rural, semi-rural and urban regions: In rural regions the ratio of the installed PV capacity can be larger than 10 times today's maximum demand in 2040, while in urban regions it can be as high as 5 times. Even though the ratio of PV installed capacity to today's maximum demand varies among different types of regions, investments which can reach up to ~ 40 MCHF in 2040 are observed in all regions types. Even though the regions exhibit high heterogeneity, the analysis shows that the required investments tend to increase non-linearly within each region type as the installed PV capacity increases. The need for investments strongly depend on the legacy network. However, the general rule is clear: without the use of flexibility, significant investments in distribution network infrastructure will be needed in order to achieve the goals of Swiss energy strategy, since the massive proliferation of rooftop PV and electrification of demand, including EVs and HPs, will progressively increase the stress on the distribution networks (i.e., causing grid violations).

Today's medium voltage (MV) and low voltage (LV) distribution networks were not designed to accommodate this paradigm shift as demonstrated in Figure 2.3. As distributed generation and new electricity demand increase, the cables and transformers will be overloaded due to the significant increase in currents, while nodal voltage violations will be observed in MV and LV grids, unless necessary measures are taken in a timely manner. Depending on (i) the condition of the legacy distribution grid (i.e., already over-dimensioned vs. already in need of upgrades) of each utility, and (ii) the proliferation pace of the new technologies, the aforementioned grid violations will appear at different instants in time. To achieve the targets of the Swiss energy strategy, while minimizing the need for upgrades of the distribution networks, our analyses of a selected set of rural, semi-urban and urban electricity distribution networks in Switzerland show that active participation of the end-users (i.e., consumers and prosumers) in the grid management is essential, providing flexibility by shifting consumption or managing the PV feed-in.

In many regions, the primary factor driving grid expansion is the rise in excess photovoltaic (PV) generation. Effectively managing PV feed-in can significantly reduce the need for grid reinforcements, while minimally affecting the total PV energy production on an annual basis. This management can be achieved through: (i) directly limiting peak power output, (ii) shifting flexible energy demand, such as EV charging and/or HP operation, to align with peak PV generation periods, or (iii) integrating local battery energy storage systems (BESS) that operate alongside PVs in a *grid-friendly* manner while maintaining self-consumption goals. PV curtailment strategies can be confidently implemented

without jeopardizing annual renewable energy generation targets [72; 70] or the levelized cost of energy for installed PV systems [79]. The reported investigations show that limiting the PV feed-in amount to 70% of the installed capacity results in an annual energy loss of less than 3% of the total annual production. Figure 2.4 demonstrates the relative reduction in total grid investments in 2030, 2035 and 2040 achieved with a flexibility-aware planning that allows a reduction of the PV instantaneous power generation by 30% of its theoretical maximum generation, compared to the investments that would be required by traditional planning (i.e., not allowing PV curtailment). It is noted that the flexibility in the form of PV curtailment based on installed PV capacity is already being implemented in Switzerland by a few electric utilities (e.g., SWL Energie), and the concerns for reliability and uncertainty are limited compared to those for the flexibility in the form of shifting and/or reducing the demand.

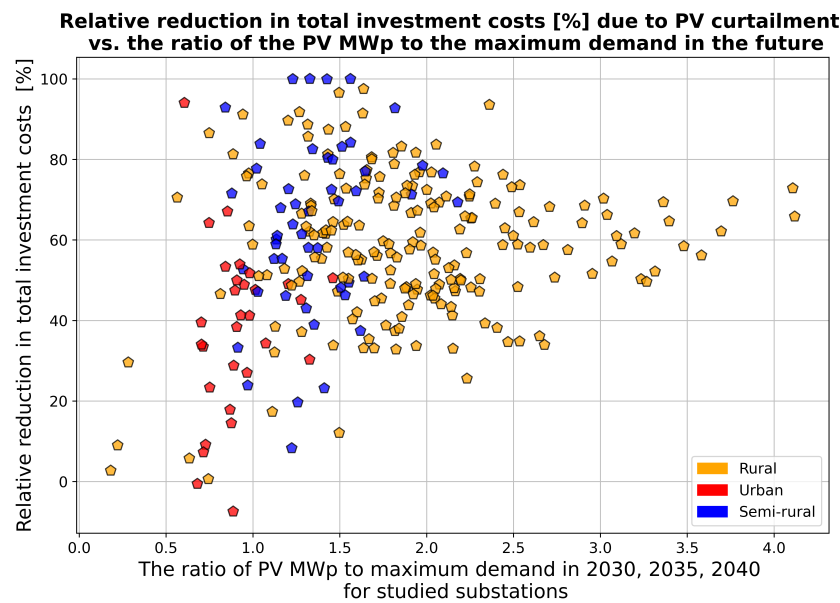


Figure 2.4: Relative reduction in total investment costs [%] due to PV curtailment and the ratio of the PV installed capacity to the maximum new demand (including new HPs and EV charging) in 2030, 2035 and 2040 for studied substations. Compare it to Figure 2.3 where the ratio is provided with respect to the maximum demand today. Grouping is based on the type of region: urban, rural and semi-rural.

The ratio of installed PV capacity in 2030, 2035 and 2040 to maximum future demand (including new HPs and EV charging) in 2030, 2035 and 2040, respectively is used as an indicator to illustrate the regional heterogeneity as well as the impact of PV proliferation on the total investment costs. In all types of regions, examples can be observed where PV curtailment reduces the total investments by more than 80%, especially where the ratio of the installed PV capacity to future demand is lower than 2.5. In the majority of the urban regions, where the ratio of the installed PV capacity to future demand is below 1.5, the curtailment reduces investments costs between 20% and 80%, depending on the target year. In rural regions, the ratio of the installed capacities to the future demand is the highest, as high as ~ 4 . The relative benefit of the curtailment tends to saturate in rural regions as the ratio increases. In 2040, the median reduction in total grid investments by curtailing less than 3% of the available PV energy is $\sim 50\%$ in the studied rural regions in 2040, while it is $\sim 40\%$ in urban regions and $\sim 60\%$ in semi-rural regions.

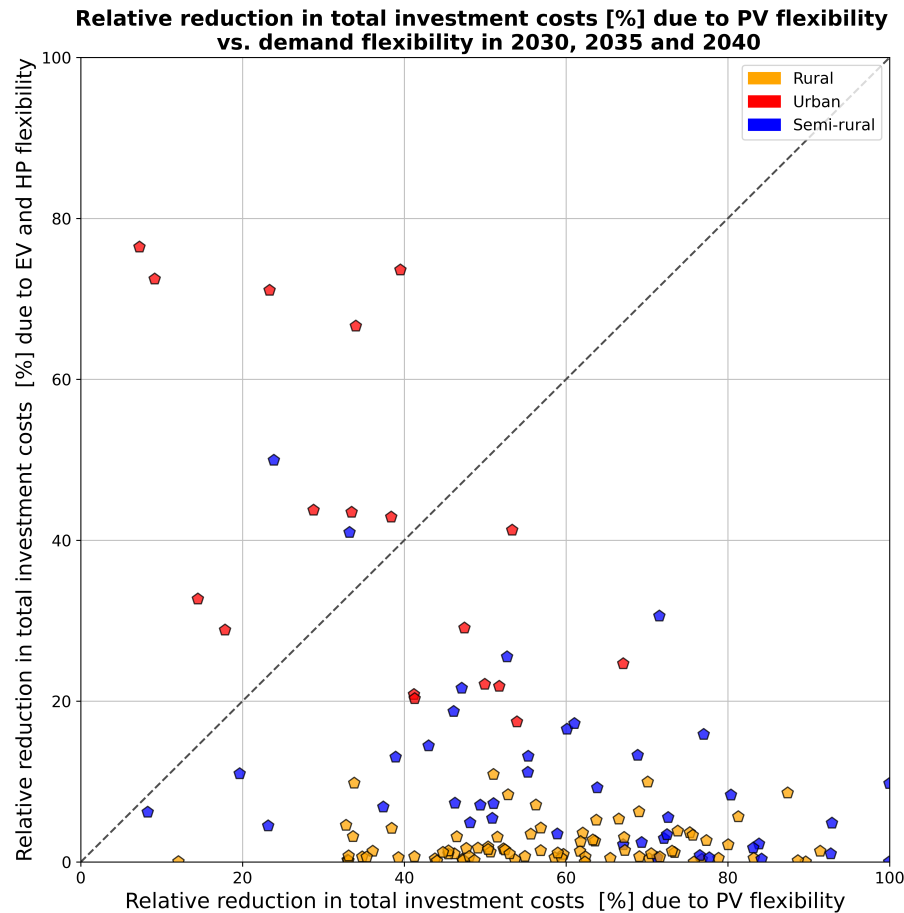
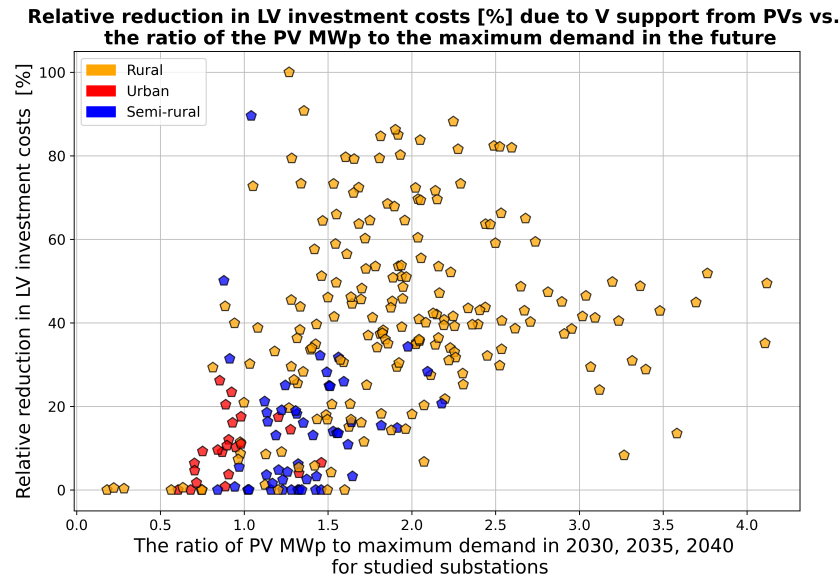


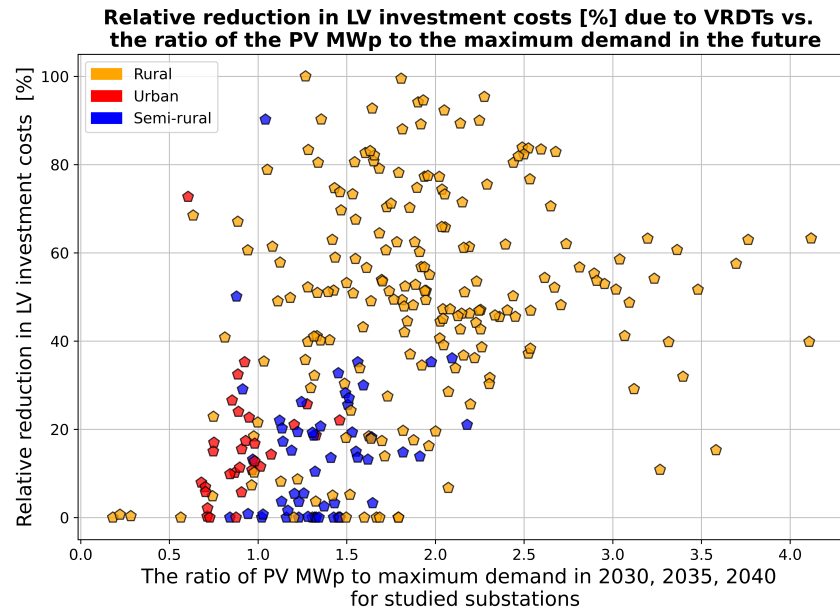
Figure 2.5: Relative reduction in total investment costs [%] due to PV curtailment and demand (EV and HP) flexibilities in 2030, 2035 and 2040 for studied substations. Grouping is based on the type of region: urban, rural and semi-rural.

In addition to PV injections, EV charging will also be a stress factor (i.e., causing grid violations) for the distribution networks in dense urban regions [13; 77]. The most effective solution, identified by means of network simulations, is flexible EV charging, i.e., regulating the rate of EV charging (e.g., limiting the charging capacity, incentivizing grid-friendly charging). Flexible charging of EVs is the demand-side resource with the greatest potential to facilitate a higher PV penetration. This flexibility potential can be exploited by shifting the charging, to the extent possible, to hours with high PV production.

The actual potential of this flexibility solution is highly location-constrained because it depends on the driving pattern of each EV user. In contrast, a relatively more reliable manner to provide flexibility is given by HPs shifting their operation. Figure 2.5 shows the results of the benefits of using only PV flexibility by means of curtailment and only demand flexibility by means of smart EV charging (i.e., night-time charging for residential EVs, and day-time coordinated charging for commuter EVs at the workplace parking lots) and smart shifting of HP operation (i.e., shifting operation +/- 2 hours). As expected, the PV flexibility is more relevant in rural and most of the semi-rural regions (the area below the dashed diagonal line), providing benefits as high as 100% reduction in total investment costs. In urban regions, demand flexibility results in more benefits (more than 75%), mainly observed in low and medium proliferation scenarios and in 2030 and 2035 (i.e., before full PV proliferation takes



(a) with voltage support from PV converters



(b) with VRDTs

Figure 2.6: Relative reduction in LV investment costs [%] due to (a) voltage support from PV converters and (b) VRDTs vs. the ratio of the PV MWp to the maximum demand in 2030, 2035 and 2040.

place, according to the energy strategy targets). Note that, in urban and some rural regions, both types of flexibilities have potential to provide significant benefits, for example in one urban region in a given scenario and year, the PV flexibility results in $\sim 40\%$ reduction while the demand flexibility alone results in $\sim 75\%$ reduction in total investment costs.

Besides overloading, which is the most common reason for grid upgrades, excess PV generation causes overvoltage violations, most drastically in rural grids. In some regions, voltage violations are observed to be the main reason for the grid upgrades. Flexible voltage regulation will be of very high importance and one way to achieve it is using voltage support function of converters (i.e.,

Q(V) control: controlling the nodal voltage, V , at the point of connection by adjusting the reactive power, Q , injection/withdrawal). PV converters are the natural candidates for this support, while the EV charging infrastructure and HPs are also equipped with this functionality, and can potentially provide this support. Since the voltage violations are ideally solved by local solutions, flexible voltage support by converters is the most techno-economically effective measure to regulate voltages in low voltage grids. In addition, as an example to grid flexibility, adoption of advanced control mechanisms (i.e., V(P) control where the tap positions, subsequently the secondary voltage, V , are controlled w.r.t. the direction and the amount of power, P , flowing through the transformer) in both voltage-regulating MV/LV transformers (i.e., voltage-regulating distribution transformer, VRDT or regelbarer Ortsnetztransformator, RONT) and on-load tap-changing HV/MV transformers will reduce required investments in medium- and low-voltage networks. In the results presented below the Q(V) control by PVs are assumed to be provided without any cost while the investment cost for tap-changing transformer is included in the investment cost calculations based on the assumptions outlined in [77].

Figures 2.6a and 2.6b demonstrate the benefits of using voltage support by PV converters and deploying VRDTs with advanced control, respectively. The ratio of installed PV capacity in 2030, 2035 and 2040 to the maximum future demand in 2030, 2035, and 2040, respectively, is used as an indicator (in the x-axis). It is observed that the median reduction in grid investments in low-voltage grids by employing the voltage support by PV converters is $\sim 40\%$ in 2040, while it is 10% in urban regions and 14% in semi-rural regions Figure 2.6a. The benefits of the voltage support by PV converters are the highest in rural regions, as high as 100%, while the benefits in urban regions are rather modest and are mostly below 20%, mainly due to the fact that the ratio of the maximum PV installed capacity to the maximum demand is relatively low. Rather similar conclusions can be drawn from Figure 2.6b, where the median reduction in low voltage grid investments by employing VRDTs with advanced control mechanisms (i.e., V(P) characteristics) is $\sim 50\%$ in the studied rural regions in 2040, while it is 16% in urban regions and 15% in semi-rural regions. The benefits of deploying VRDTs are the highest in rural regions (as high as 100%) similar to the benefits of using voltage support from PV converters and VRDTs provide slightly more benefits in urban regions compared to the PV converters. However, the investment costs of VRDTs with advanced control might be the disadvantage compared to the voltage support from PV converters, which might be an already required functionality with no additional cost. Since the voltage violations often occur due to excess PV generation, shifting the EV charging and HP demand to excess PV instants would be beneficial as such flexibility will indirectly mitigate the overvoltage violations due to PV feed-in.

In summary, utilities must anticipate and prepare to accommodate the new paradigm with unprecedented levels of distributed generation, EVs, and electric HPs. They will often be required to upgrade their networks; however, upgrading the grids to accommodate the projected peaks of power injections due to solar PV generation, which occur infrequently, and/or withdrawals due to new demand could require upgrades of many cables and transformers will be very costly. Utilities must devise schemes and provide incentives to the end-users to limit peak injections caused by excess PV generation and the peak withdrawals caused by the new electricity demand. Clearly, shifting the demand due to EV charging and HP operation to hours of high PV production, whenever this is possible, will facilitate reduction or deferral of the distribution grid investments.

Methodologies for flexibility-aware distribution network planning, as the one developed in PATHFNDR, shall eventually become the new standard. Such approaches will allow the utilities to defer network investments by engaging local flexibility, as well as to identify the value of flexibility services.

3 Quantifying flexibility from EVs and HPs

Section 2 of this report showed that flexible demand can add value at the system level by avoiding PV curtailment and reducing system costs, imports, prices, and investment in new infrastructure, and at the distribution level by reduced grid reinforcement costs.

The scale of these benefits is limited by the availability of flexibility: where, when, and by how much can the demand from EVs and HPs be shifted? In this section, we dive into PATHFNDR research on the quantification of EV and HP flexibility. This section does not include new analysis run solely for this report, but summarizes and synthesizes the findings from a number of research papers and models from across the PATHFNDR project.

3.1 Quantifying heat pump flexibility

As part of Switzerland's energy transition strategy, it is projected that the electrical demand from HPs will nearly quadruple by 2050, from 3.3 TWh to 9.0 TWh [80], as total HP installations would increase from 0.3 to 1.5 million [80]. Estimates range to even higher consumption of up to 11.7 TWh [3] or up to 17 TWh (see analysis in section 2.1) with different modelling assumptions. Relative to an annual electricity consumption in 2050 excluding EVs and HPs of approximately 53 TWh, that amounts to an additional demand of at least 17%.

Older buildings account for most of Switzerland's residential heating demands: of the annual heating energy demand of 32 TWh, pre-1980s buildings account for roughly two-thirds [81]. Sixty percent of the residential heating demand is still provided using natural gas or heating oil. As older buildings are also more likely than new buildings to be heated by natural gas or oil, retrofitting to new heating technologies like HPs is an important part of building decarbonization strategies [82]. HP deployment in Switzerland has so far been skewed toward rural areas and varies substantially across cantons [83].

Flexible operation of HPs, without comfort loss, can be achieved through the storage of thermal energy, either in dedicated thermal energy storage devices such as hot water tanks, or by utilising the thermal mass of buildings themselves.

Monitoring data shows that buildings generally have a slow rate of indoor temperature decay in response to heating system shut-offs. In a diverse sample of over 20 buildings (construction decade ranging from 1900 to 2010, median: 1970s), no building exhibited a mean cool-down rate exceeding 0.5°C per hour during heating system shut-offs, even for buildings with high specific annual heating demands of over 100 kWh/m² (typically older buildings) and in sub-zero weather. The significant storage capacity of buildings allows HP loads to be curtailed for periods between 2 to 10 hours in

cold weather (outdoor temperature of 0°C) without buildings falling into an uncomfortable temperature range - up to 10 hours in renovated or new Minergie-level buildings [19]. As a reference, an average HP can shift about 7 kW over a 2-hour curtailment (around 14 kWh) at 0°C. Scaled to all buildings in Kanton Zürich, this would correspond to around 1.7 GWh of shiftable load if every building were equipped with a HP.

DSOs in Switzerland typically limit load interruptions to a maximum of two hours [22]. Simulated whole-community HP curtailments show these limits to be generally safe for the majority of buildings, with fewer than 5% losing more than 1°C during a two-hour heating interruption in 0°C weather. HP curtailment strategies that incorporate the building temperature can limit underheating in buildings while still achieving similar power reductions to full shut-offs [19].

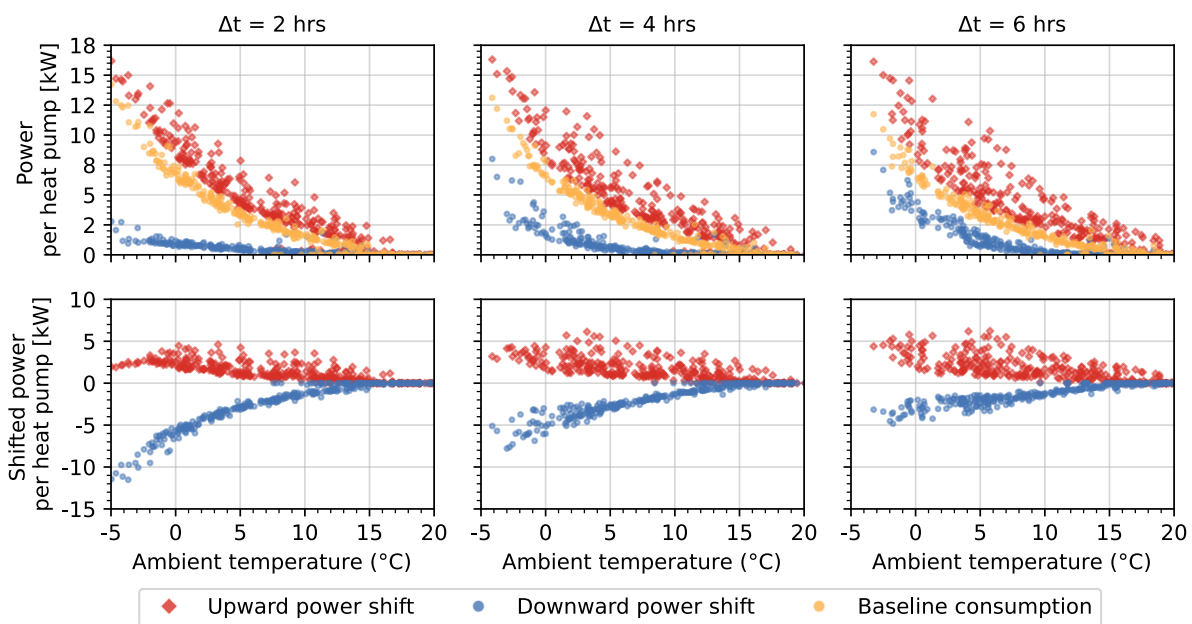
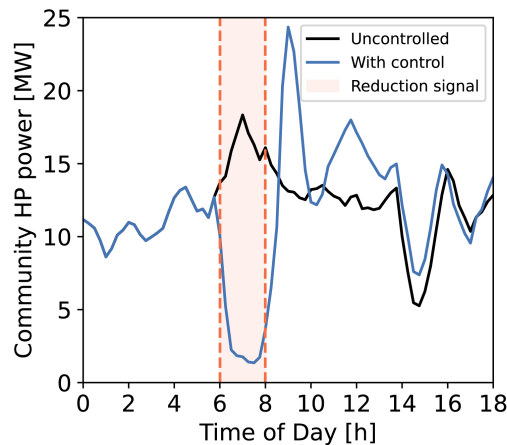


Figure 3.1: This figure shows the shiftable power per heat pump under varying weather [19].

However, grid operators must be also aware of rebound effects following HP curtailments as building and buffer storage temperatures recover, like the rebound peak shown in Figure 3.2a. Demand response events in cold weather ($<0^{\circ}\text{C}$) can potentially result in HP simultaneity factors of 100% if all HPs are curtailed at the same time. The peak and duration of the rebound effect is strongly linked to the individual control strategy of the HP and building [19].

At the community level, coordination of multiple buildings' thermal inertia improves the flexibility potential and can help to resolve congestion and peak demand [84]. This aggregation can also help address technical constraints of real-world implementations, as demonstrated in the PATHFINDER P&D nanoverbund project, illustrated in Figure 3.2b. The project uses control and automation algorithms that create flexible prosumers, allowing HPs to serve multiple buildings. In winter, one building's HP can additionally heat adjacent buildings, while in summer, solar thermal collectors recharge the system. In ongoing research in the nanoverbund project, an agent-based approach was used to model buildings' joint optimisation of their heating demands using energy flexibility from thermal inertia, all with minimal exchange of private information [85].

a. Simulation of HP flexibility



b. Illustration of nanoverbund

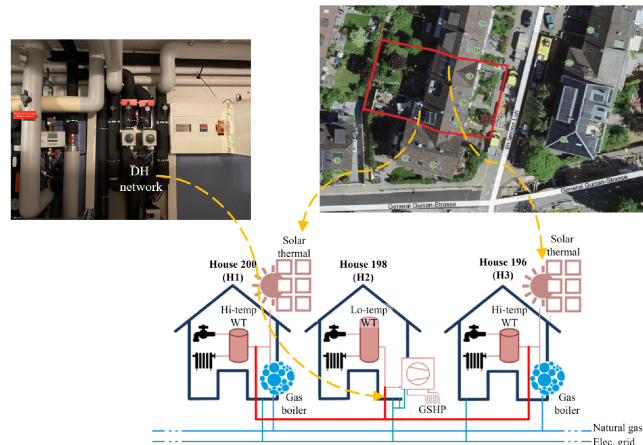


Figure 3.2: (a) Illustration of HP flexibility and rebound peak for a sample day [19]. The "Uncontrolled" series, representing the base case where HPs operate normally without any flexibility action requested, shows the HP demand without any signal; the "With control" series shows how the demand could be shifted to respond to a reduction signal during the peak period from 6 to 8 a.m., while maintaining thermal comfort in the building. (b) The nanoverbund concept and test site [20]. This figure demonstrates the large potential flexibility in HP demand and illustrates the concept of the nanoverbund.

New techniques like model-predictive control (MPC) introduce ways for buildings to optimize their operations and respond to dynamic electricity prices or emission signals and changes in the weather, while also maintaining thermal comfort. In recent demonstrations at the NEST test site at Empa, operating HPs combined with buffer water storage tanks flexibly using MPC has been shown to result in energy, emissions and cost savings of 6.1%, 13.8% and 8.0% respectively compared to conventional control [86].

The thermal inertia of the building stock enables substantial flexibility throughout both urban and rural regions of Switzerland [19]. Transmission and distribution grid operators can benefit from this flexibility to stabilize their grid operations. However, a key enabling factor is the controllability of HPs [87]. This requires utilities to either mandate HP controllability as part of their connection criteria or provide incentives to end-users to encourage their participation.

Discussions of HP flexibility are usually focused on the hourly scale, but the largest disparities between renewable energy supply and HP demands exist on a seasonal (summer-winter) scale. Seasonal thermal energy storage presents a promising technological solution for seasonal shifting of HP loads. Seasonal thermal energy storage offers a promising technological solution for seasonal shifting of HP loads. This can be achieved via a large-scale pit or borehole storage linked to a large HP in a district heating network, or through the regeneration of borehole fields with free cooling in summer. The combined effect of these approaches could reduce the Switzerland's additional winter electricity demand for heating by a few TWh [88]. Cold thermal storage (for example, using ice) may also enable the shifting of cooling HP loads from winter to summer [89].

In summary, heating demand for almost all buildings in Switzerland can be adjusted to meet energy system needs without impacting occupants' comfort, with shifts of at least 2 hours possible using just the buildings' thermal mass or shifts over longer periods with the use of thermal energy storage devices like hot water heaters. The incentives and mechanisms needed to access this flexibility from HPs are described in Section 4.

3.2 Quantifying electric vehicle flexibility

Wide-scale electrification of the light-duty and passenger vehicle fleet will add new electricity demand in 2050 equal to approximately 13.4 TWh [15]. Estimates range from 11.4 TWh [14] to 17 TWh (see analysis in Section 2.1), depending on modeling assumptions, and can reach higher values with the additional consideration of commercial vehicles [3]. In the remainder of this section, we refer to results for modeling of private passenger vehicles. Relative to an annual electricity consumption in 2050 excluding EVs and HPs of approximately 53 TWh, that amounts to an additional demand of at least 22%.

There is an opportunity to use flexibility to reduce impacts on the system while still ensuring car batteries are charged and capable for all upcoming trips. The available flexibility varies with location and time and depends on many factors, both technological and behavioural [90].

Recent research presenting a new modelling framework for battery EV demand in Switzerland combines detailed mobility data and models of driving energy consumption to investigate this variation, with the following key findings: EV energy consumption is up to 16% higher on the coldest days of the year, compared to the warmest days, independent of any changes in driving patterns [15]. Driving patterns vary across different regions of Switzerland: per capita energy consumption tends to be highest in rural areas, especially in the Alps region, and lowest in urban areas of Switzerland. Total energy consumption from EVs is highest in urban areas due to their higher population [15].

Flexibility is limited by when and where vehicles are parked and by when and where they have the opportunity to plug in. While most vehicles are parked at home most of the time, substantial opportunities may also arise at other locations: 40% of daily mobile vehicles park near work or education locations during the day on weekdays, and 15-20% park near leisure or shopping locations during the day on weekends [15]. Many people in Switzerland commute between different regions when they go from home to work or school to shopping and recreation: if drivers chose to charge more near their work and education locations, there would be an increase in charging demand in urban areas and a concentration of load in a small percentage of regions; if drivers chose to charge more while running errands, there would be little change in geographic concentration compared to charging at home; and if drivers chose to charge more while at leisure locations, there would be a decrease in charging demand in urban areas and a more even distribution of demand across regions [15]. These potential shifts, illustrated in Figure 3.3, show the importance of understanding drivers' charging behaviour to plan for the locations of their charging demand and show the spacial dimension of EV flexibility potential that could benefit the electricity system. These shifts are also limited by the availability of different charging options; more public and workplace charging infrastructure would be needed to facilitate a shift toward more charging near work, education, and errand or leisure locations.

Further research has investigated these shifts as an optimization problem, combining the EXPANSE electricity system model for Switzerland with detailed municipality-level commute patterns [14]. The results show that a shift toward workplace charging in Switzerland could support the integration of PV in some scenarios. To minimize costs for the electricity system, the optimal share of drivers choosing workplace charging over home charging is very high (>90% across most scenarios) [14].

Flexibility also depends on who implements charging control and how. If independent aggregators control the loads, they will tend to dispatch flexibility without pricing in the cost of unscheduled

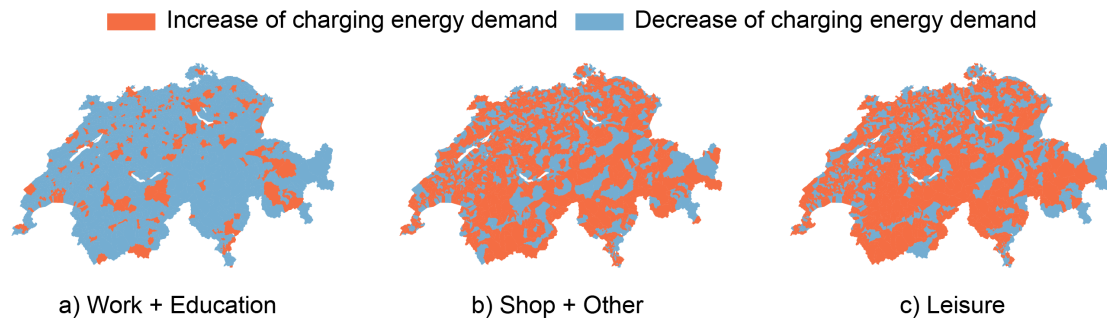


Figure 3.3: Spatial shift in charging energy requirements based on changing charging from home to other locations [15]. This figure shows that shifting between charging locations could have diverse impacts on local grids and communities depending on local geographies and mobility patterns.

catch-up consumption (i.e., additional consumption that occurs later to compensate for previously curtailed demand). This will create imbalances for load-serving entities that are hard to quantify and compensate for. As a result, dispatch by independent aggregators is likely to be less efficient and less aligned with system needs. If on the other hand separately metered flexible loads are dispatched by “specialized energy providers” (e.g., HP or car manufacturers) this could enhance the efficiency of dispatch and improve the volume of flexibility that is available. These specialized energy providers will have a better understanding of the operating limits of flexible loads, enabling them to dispatch flexibility more efficiently and with a lower risk of damaging the devices [24].

For grid operators, workplace charging offers high potential benefits due to long plug-in times and the natural alignment with hours of high PV production (i.e. over noon time). Flexibility is also generally higher for residential and workplace charging than for public charging, where costs are higher, sessions are shorter, and drivers expect fast charging times.

Controlled charging can involve delaying, modulating or shifting charging demand to different times, e.g., to maximize the use of renewables, to reduce grid stress, or to minimize electricity costs [16]. Conventional flexibility or smart charging is also called V1G; although the timing and rate of charging can change, the direction of power flow is always from the grid to the vehicle. V2G extends this concept to allow for bi-directional charging, including power flow from the vehicle back to the grid. Figure 3.4 presents examples of V1G and V2G control from recent research. Recently, vehicle-to-home concepts are also emerging, which allow EV batteries to be used as energy storage for homes, enhancing self-consumption of locally generated renewable energy.

Workplaces are the most common site for V2G demonstrations [91]. Workplace V1G can reduce PV curtailment by shifting consumption to peak solar hours; V2G can reduce curtailment even more by discharging to the grid ahead of peak PV hours to free up more space in the batteries to absorb excess PV generation. Recent research combining a model of V2G for workplace charging with Nexus-e simulations of future curtailment patterns found that V2G could reduce curtailment by an estimated 2 MWh per workplace station per year in Switzerland in 2050 [18]. To put that roughly in context, the total annual curtailment discussed in Section 2 was between 6 and 8 TWh.

Additional cycling of EV batteries to provide flexibility services may come at the cost of reduced battery lifetimes. Fortunately, recent research based on over five years of operational data for a stationary battery energy storage system suggests impacts through calendar and cyclic ageing are small [92]. Further, simple battery degradation models are sufficient to predict effective battery degradation from

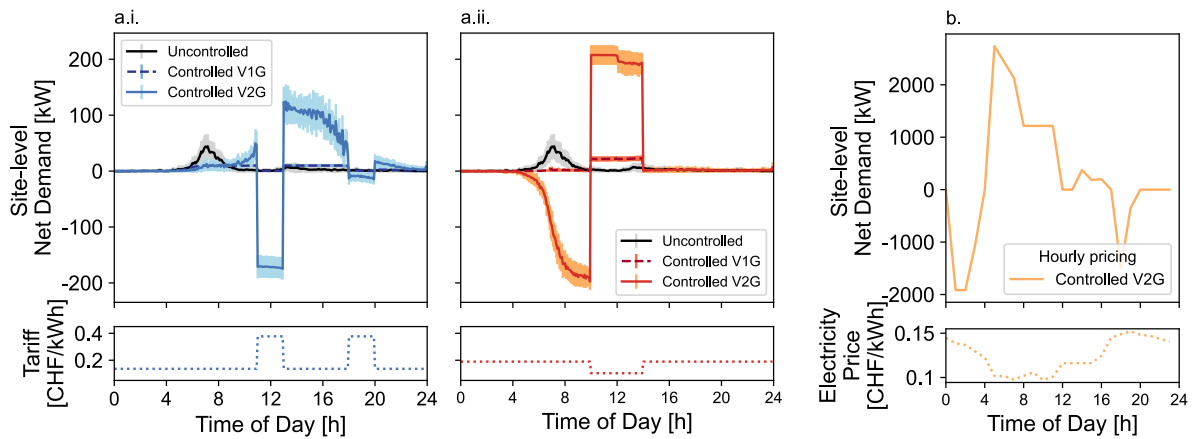


Figure 3.4: (a) Comparing uncontrolled, V1G, and V2G charging demand for a workplace charging site in Switzerland with 25 charging stations, with time-of-use tariffs based on peak periods (a.i) or PV periods (a.ii) [18] (CC BY 4.0 license). Lines and shaded areas show the mean and standard deviation over 50 model runs reflecting variation over different driver profiles. (b) Relationship between hourly variable electricity price and controlled V2G charging profile for a test site in [16]. This figure shows the substantial potential flexibility from flexible EV charging, especially with V2G.

a data-driven perspective for flexibility use cases like at the NEST test site, even under intense usage. In a simulation based on historical prices, the impact of flexible battery operation on ageing costs was so small that including the cost term for battery degradation in the optimization had no impact on cost-optimal operation [92]. These results, however, are based on a stationary battery energy storage system, which may have different operating conditions and battery chemistry than many EVs.

Compared to HPs used for space heating and domestic water heating, EVs can offer more than four times as much flexibility potential in residential energy systems, but their availability is harder to forecast [17]. Considering user-specific behaviors and local conditions such as temperature can improve the forecasting of EV flexibility [93].

4 How can we enable flexibility from EVs and HPs?

In order for the flexibility potential that can be provided by EVs and HPs to be made available to the system operators, two conditions need to be met. First, EVs and HPs must be equipped with the required control and communication capabilities. EV chargers, HP controllers, and other flexibility devices must be standardised (e.g., SmartGridready), follow the same communication protocols, allow remote operation, and support two-way communication with grid operators or other flexibility providers [19]. Since this requirement increases the installation costs, while currently the potential benefits to the customer are still unclear, appropriate policies and regulations are required, to ensure that the installations are “flexibility-provision-ready”. Second, for EVs and HPs to provide flexibility to the system, appropriate mechanisms shall be in place that either motivate them to do so (by means of price signals) or force them to do so (by means of regulations).

The full potential flexibility of EVs and HPs can only be realized if multiple levels of policy and market mechanisms are in place, and if those measures are accepted by EV and HP owners.

In this section, we summarize findings on a range of possible policy and market solutions studied in PATHFNDR.

4.1 Policy, regulation and business strategies

Policymakers and regulators have a wide range of potential tools to increase the available flexibility from EVs and HPs. These range from “carrot” policies of encouragement like subsidies and financial incentives to “stick” regulations that force individuals and businesses to meet a minimum standard.

Regulations and policies for demand-side flexibility are being introduced to support both “simple” to “flexible” electrification, as shown in Figure 4.1. These policies address the infrastructure side, supporting the installation of smart meters as well as new EV chargers that have the necessary communication and control capabilities, and the operations side, ensuring that variable electricity pricing or other flexibility procurement mechanisms are well designed and are applied to new sources of flexible demand. Comparing Switzerland with its neighbours, the results of a detailed review show that flexible integration of electrified assets is being addressed by policymakers in all 5 countries and in the EU, with regulatory and policy frameworks evolving to support a more flexible and efficient system [21].

Increasing the availability of flexibility-ready charging stations is key to increasing the flexibility of EV demand. Some Swiss cantons are subsidizing V1G and V2G chargers, although none have adopted domestic “right to charge” regulations which require landlords to grant tenants’ requests for charging access. In terms of incentives, dynamic pricing and direct load control contracts for EVs and HPs

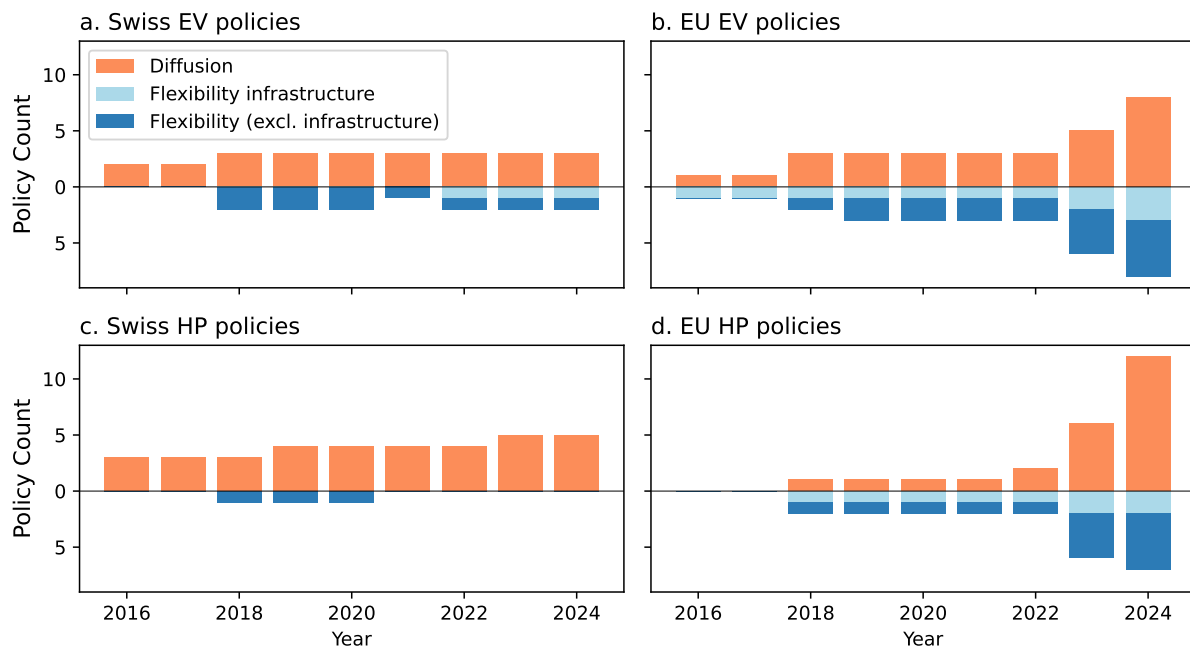


Figure 4.1: Comparing the number of policies for EV and HP diffusion and flexibility across Switzerland and the EU [21] (CC BY 4.0 license). This figure shows that policy in Switzerland has focused more on diffusion and less on flexibility than policy in the EU.

have been introduced in some places. Switzerland's unique DSO-supplier model offers advantages for direct load control, but it is only in place for a limited number of customers, cases, and regions [21].

Currently, there is no viable business case for small-scale V2G aggregators due to a combination of high station costs, outdated tariff design, and regulations allowing "double taxation" and the double application of network charges for discharged energy [18]. New policies attempt to address these regulatory issues [94], but those will not be enough on their own. Price spreads need to be large enough in customer-facing tariffs to incentivize V2G despite round-trip losses and, until prices fall for V2G capable charging stations, policy support through direct subsidies may be needed [18]. A cost-benefit analysis suggests that V2G station subsidies are a very expensive way to achieve emission reductions in the near term [18], but policymakers should also weigh the policy cost against long-term impacts on the industry. As low production volumes, not hardware costs, are the main reason for today's high V2G station prices, wider V2G station deployment could induce learning effects that cause prices to fall. Yet, increased production volumes in Switzerland alone would likely be too small to impact global trends and manufacturing costs.

New policies can also trigger innovations at the municipal level on the path to net-zero emissions, as seen in multiple Swiss cities (e.g., Basel, Lucerne, and Bern). Publicly owned utilities should lead in promoting climate solutions like the phase out of gas heating. HPs have high upfront investment costs, but typically lower lifetime costs than other heating technologies. Challenges remain, however, including a mismatch in incentives and cost responsibility between owners and tenants.

As subsidies are often needed to reduce the upfront costs for private building owners, this suggests a need for new financing solutions. For example, instead of each resident owning their own HP, the DSO could purchase the HP and charge residents based on their heating consumption. At the

same time, utilities must also find new revenue sources to replace lost income from gas. Examples like the nanoverbund project provide another viable solution: using pooled flexibility across multiple buildings allows building owners to build micro-thermal grids and helps innovators enter new markets, challenging traditional utilities reliant on existing infrastructure [23].

4.2 Operational and market mechanisms

Flexible loads can be controlled by an independent system operator, the transmission system operator, the distribution system operator, the energy provider, an independent aggregator or the prosumers themselves. If loads are controlled by more than one entity at the same time, coordination is required to determine which dispatch signal takes priority in case of conflicts to avoid violating the operational limits of the transmission grid, distribution grid or individual devices.

Given the infrastructure and intention to use EV and HP flexibility, there are many possibilities for the detailed, hour-by-hour implementation and operations. Several possible setups are illustrated in Figure 4.2. Each case involves: (1) a signal from the utility or other system operator communicating where or when to shift demand; and (2) an actor controlling the response to that signal, typically either the individual EV and HP owner or an aggregator of multiple EVs or HPs. Aggregators may control a small number of devices, like across a single parking lot or multi-family building, or a very large number of devices across multiple locations [63]. The best signal design is an area of intense research.

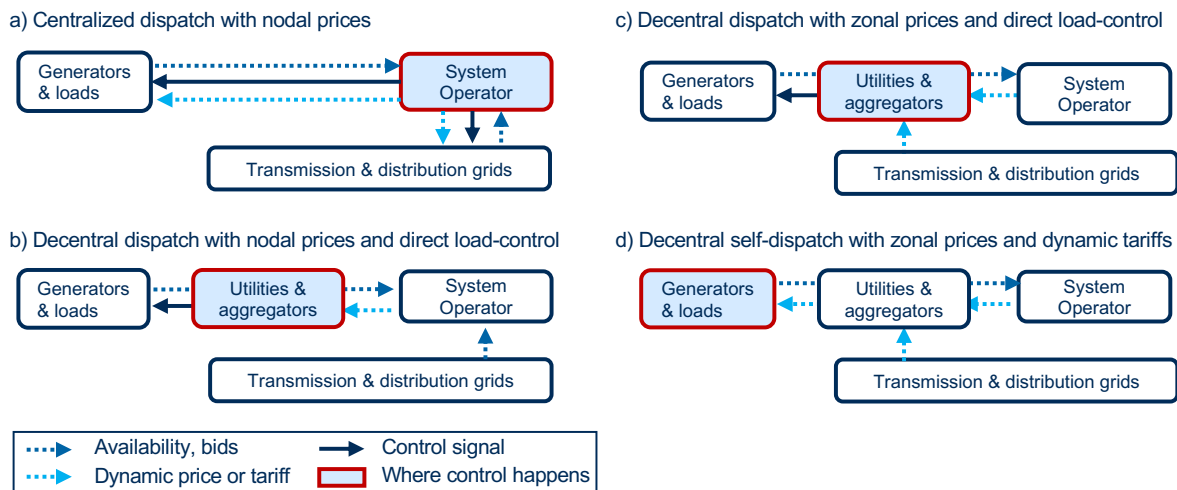


Figure 4.2: Example market arrangements for implementing control of EVs and HPs [24]. This figure shows the complexity of implementing flexibility and the many possible configurations of the different actors.

One way to activate this flexibility is through direct load control, where a system operator, energy supplier, or aggregator sends signals to adjust electricity consumption (Figure 4.2a), such as turning a HP on or off. If the system operator (TSO or DSO) had full control over flexible loads, they could optimize their dispatch while considering system constraints [95]. However, such centralized control would require a shift away from the current European and Swiss decentralized market model, where energy suppliers and consumers decide when to use electricity.

Instead, direct load control by energy supplier or by third-party aggregators would be more compatible with the existing European market-clearing approach (Figure 4.2b). Switzerland already offers optional contracts for direct load control of HPs, EVs or residential water heaters, but broader implementation faces barriers such as costs, communications infrastructure, and privacy concerns. In some cases, direct load control has been enforced during emergencies (as seen in France and Switzerland) or incentivized through reduced grid fees (as seen in Austria and Germany) [21].

If energy suppliers manage direct load control, this would allow them to anticipate demand surges after flexibility events. By contrast to aggregators, energy suppliers would procure the additional energy required for this catch-up consumption in the intraday market to avoid imbalances. They will thus consider not only the benefits but also the cost of load shifting in their dispatch decisions, resulting in a more efficient dispatch than the a decentralized control by aggregators [24].

In cases where flexibility aggregators participate in wholesale markets, existing bid formats would need to be revised to support the integration of flexibility aggregators into the wholesale markets as they are predominantly designed for conventional power plants [27]. In addition, in absence of nodal energy prices, energy suppliers need to be provided with an additional signal reflecting local grid congestion or capacity, which incentivizes them to take into account the impact of their dispatch on the grid (Figure 4.2c).

As a third, less direct approach, the utility or system operator can send pricing signals to incentivize shifts in demand (Figure 4.2d). Dynamic pricing signals which change in near real-time can communicate efficient incentives to flexible loads. At the system level, hourly dynamic prices based on real-time wholesale electricity prices can offer significant system-level cost savings by better aligning EV charging with domestic PV production as well as importing cheaper, carbon-free electricity [96].

Compared to direct load-control by aggregators or energy suppliers, one of the main advantages of dynamic pricing is, that it provides an elegant way for coordinating the dispatch and resolving conflicting activation signals. In case of dynamic pricing, the signals from dynamic grid charges, spot prices and balancing markets can be added up, so that customers will dispatch in a way that maximizes overall benefit. This is both conceptually more simple and likely more efficient than the establishment of administrative activation rules and priorities. However, as we will discuss further in the next section on social acceptance, updated regulations are needed to make dynamic tariffs available to a wider range of consumers [21].

Static electricity tariffs are more common today than dynamic pricing. Most consumers experience flat or static time-of-use tariffs with simple peak/off-peak periods [21]. Though less efficient than dynamic pricing, simpler tariffs are easier to implement and can unlock some non-automated, behavioural demand flexibility. Time-of-use tariffs can communicate the basic information with, for example, low prices during hours with typically high solar generation or high prices during hours of peak demand on the grid [96].

Rebound peaks, also called over-coordination or the avalanche effect, are an important risk of time-of-use tariffs and even of day-ahead dynamic pricing [25]. With a large share of automated loads, any variable price signal per kWh fixed ex-ante (e.g., day-ahead) can create rebound peaks, as all flexible loads that are automatically controlled and connected turn on during the lowest-price period. Capacity-based prices, charged based on the consumer's peak rather than total consumption, can help prevent rebound peaks, but are also shown to reduce load-shifting. Forthcoming research suggests that a hybrid solution could perform best, combining dynamic energy prices (volumetric

prices) with different types of capacity prices, which reduce the incentive for over-coordination. Capacity prices can also help specifically with distribution network planning, deferring the need for grid investments by avoiding high peaks in demand [97]. However, to our knowledge many of the energy management systems which are currently used in the market have not yet implemented the interfaces for collecting dynamic price signals from grid operators and / or lack the ability to optimize dispatch in case of hybrid tariffs, based on combinations of dynamic energy and capacity prices [98].

4.3 Social acceptance

Individual preferences, such as the desire for cost savings or maintaining comfort, are a crucial part of designing pricing or control mechanisms that work for both consumers and the system.

Past studies have consistently shown customers aversion to dynamic, real-time pricing and their preference for constant energy prices [99]. Survey results show that automation can reduce customers' aversion to volatile prices and make dynamic time-of-use tariffs as acceptable as static time-of-use tariffs [29]. An even more attractive option could be the combination of fixed prices with direct load control. Offering a contract menu including flat-rates for customers with automatic direct load control and time-of-use tariff for non-automated customers, could encourage load-shifting and help prevent rebound peaks. 57% of the customers, primarily younger and more automation-inclined, would likely opt for direct load control with flat rates. While 28% would prefer a time-of-use tariff with manual load control, and 15% would avoid load-shifting incentives altogether [31].

In terms of the trade-off between cost and thermal comfort, around 30% of customers surveyed in Switzerland are willing to prioritize cost savings over some loss of comfort. 70% only choose to offer flexibility if it does not affect their comfort. The survey of 582 Swiss households showed that cost-focused customers favor contracts with low price risks and automated load control, while comfort-focused customers are unlikely to choose contracts with any risk or affect on their comfort. All customers prefer direct load control of individual appliances over demand response approaches that limit their total electricity demand [28].

To improve the acceptability of dynamic prices, they could be accompanied by separate hedge payments. Profile contracts are a promising example. In profile contracts, customers pre-agree an electricity amount and a consumption profile, with hourly deviations charged at spot prices. Profile contracts can reduce electricity bill volatility from dynamic pricing to levels similar to fixed-price contracts, protecting customers from price shocks, while preserving incentives for load-shifting and load reductions and lowering bills for flexible customers [26; 32]. This is important, because while dynamic grid charges provide incentives to address local grid-bottlenecks through load-shifting, they provide very limited incentives to reduce energy consumption in the event of future energy crises. To improve this, customers should thus be exposed to spot-market prices in addition to dynamic grid charges while at the same time being hedged against price shocks through profile contracts. However, a survey among residential customers shows, that while customers strongly value contracts which reduce their financial risk, they are less likely to select profile contracts - even if they come with a best-price guarantee - because they do not understand the risk-hedging properties of these contracts [100]. Promoting the adoption of profile contracts will thus require further efforts by the regulator and/or the utilities.

This is further underlined by an international review of more than 30 field experiments suggests that even the most acceptable tariff designs will struggle to achieve opt-in recruitment rates of more than 40%, while opt-out arrangements could achieve recruitment rates of more than 90%. In order to generate an impact, a much more important lever than the design of the tariffs themselves could thus be the introduction of opt-out recruitment [30]. The recent revision of the Stromversorgungsgesetz[2] has already paved the way for introducing default electricity tariffs with dynamic grid charges. But interviews with Swiss energy providers suggest, that it is unclear, if captive customers can be offered a tariff, which passes through the spot-market price with or without additional hedging arrangements [100]. Even if it was allowed, the interviews show that Swiss utilities are unlikely to introduce such tariffs. To promote a more widespread adoption of contracts which combine spot-market prices with dynamic grid tariffs and profile hedges, regulators should clarify, that these types of contracts are allowed as default option.

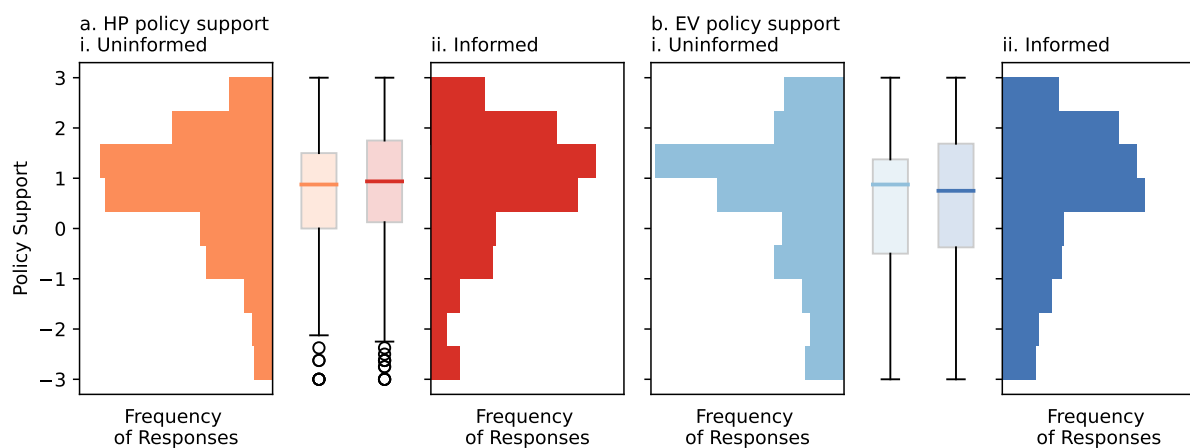


Figure 4.3: Illustration of survey respondents' shift in opinion after additional information on a policy for the flexible operation of HPs (a) and EVs (b) [33]. This figure shows that public support for EV and HP flexibility policies is broadly positive.

A related challenge is in the reliability and frequency of drivers' plug-in events. When vehicles are parked near a charger but not plugged in, they are not available to provide flexibility services to the system. Some international research has investigated the use of incentives to increase plug-in frequency to make vehicles more available [101], but further research is needed to understand Swiss drivers' motivation to plug in.

Looking beyond tariffs and pricing, a survey of Swiss citizens showed overall support for policy incentives promoting V1G flexible EV charging stations and the flexible operation of HPs, as illustrated in Figure 4.3. This support was quite robust; giving the survey respondents additional information about the potential impacts of these policies on emissions, health, costs, comfort, data protection, jobs, or renewable integration had little impact on the result [33]. There are other positive signs related to flexibility and the energy transition in Switzerland. Notably, the Mantelerlass electricity law supporting a more rapid transition to renewables passed a national referendum with 68.7% of the vote in 2024 [2]. More research on the acceptance of flexibility policies and market mechanisms can help inform the design of future laws and smooth the path toward a more flexible Swiss energy system.

5 Future research

Our analysis of the system-level benefits from EV and HP flexibility revealed substantial synergies between the two: the "Both on" flexibility case was even better than the sum of "EV only" or "HP only" flexibility in some metrics. Further research is needed to understand and better characterise these synergies.

Additional simulations are also needed to understand the sensitivity of the results to important assumptions such as lower rates of flexibility adoption or available flexibility, different availability of charging options (e.g. more or fewer workplace charging stations), different climate years affecting hydro production and availability, lower renewables build-out, and changes to the underlying regulatory and policy framework of the energy system in Switzerland (e.g. discontinuation of the integration agreement with the EU).

More research is also needed to help policymakers prioritize investments in different flexibility options (V1G, V2G, flexible HPs, etc.) in the near term.

To fully unlock flexibility, further investigation is required into policy and market mechanisms as well as social acceptance strategies. New financing models are required for EVs and HPs, particularly in rental properties where tenant-landlord split incentives limit adoption. Furthermore, more research from the user perspective is needed on the financial viability of V2G given current high station costs and uncertainties around market revenues for flexibility services. Ongoing research in PATHFINDER is working to estimate the total benefits of V2G across system levels to facilitate a more complete cost benefit analysis. More work is needed to explore how costs for implementing EV and HP flexibility impact its use and benefits at the system-level, and could explore scenarios with varying implementation costs and participation rates. Not all EVs may need to participate in V2G services to maximize system benefits. Consumer research should also explore how pricing structures and incentives impact participation, ensuring that flexibility mechanisms align with user preferences.

Future studies should also focus on improving forecasting models for EV and HP flexibility, accounting for behavioural patterns, regional variations, and acceptance issues like plug-in frequency. There is an urgent need to test and demonstrate innovative solutions through real-life implementation, such as the pooled heating flexibility in the "nanoverbund" project, to inform scalable solutions for integrating flexibility into Switzerland's energy system.

The uncertainty in estimating available and reliable end-user flexibilities (especially from HPs and EVs) remains a key challenge for DSOs. Stochastic assessment of EV charging patterns and HP operation profiles will help the utilities to efficiently estimate reliable flexibilities and incorporate the end-user flexibilities into flexibility-aware grid planning.

6 Stakeholder recommendations

Recommendations from these findings suggest that unlocking the flexibility potential of EVs and HPs requires coordinated action across relevant stakeholder groups. The following recommendations are structured by stakeholder type, including the federal government (Bund), cantons and municipalities, transmission system operators (TSOs), distribution system operators (DSOs) and utilities, aggregators and energy suppliers, as well as technology providers and manufacturers, to reflect their specific roles in enabling and scaling flexibility.

Federal government

- Create incentive schemes for end-users for the combined adoption of EVs, flexibility-ready charging infrastructure, and flexibility-ready HPs to reduce emissions and realize benefits from EV and HP demand flexibility, including from lower electricity prices to facilitate the integration of renewable generation (see full report in sections 2.1 and 4.1).
- Mandate a nationwide “right-to-charge” compliant with smart charging standards for tenants in multi-dwelling buildings to remove access barriers, support V1G/V2G by regulating flexibility-ready, interoperable infrastructure, and mandate that suppliers offer dynamic tariffs to enable end-users to offer their flexibility (see full report in sections 3.2 and 4.1).
- Require that HPs and EV charging devices are smart-ready, interoperable by default and compatible with open standards to enable automated flexibility across devices and markets (see full report in section 4).
- Promote a combination of dynamic tariffs with profile contracts as default option for customers with smart meter (opt-out) to shift EV/HP demand to hours with high PV generation, cutting end-user bills and avoiding grid congestion (see full report in section 4.2).
- Ensure that aggregators and energy suppliers with flexible loads can effectively participate in day-ahead and intraday auctions, while maintaining coordination among TSOs, DSOs, suppliers, and prosumers to prevent conflicting dispatch signals (see full report in Section 4.2).

Canton and municipality

- Promote local flexibility by providing incentives for controllable heat pumps, shared thermal networks, and smart EV charging (V1G/V2G) to scale participation, reduce grid stress, and unlock new revenue streams (see full report in sections 3.1, 3.2 and 4.1).
- Integrate flexibility-readiness into permitting by requiring controllable HPs in connection or building codes to reduce retrofit barriers and activate flexible demand (see full report in section 3.1).

- Support the deployment of V1G and V2G infrastructure at public and workplace sites to facilitate a shift in charging toward hours of high PV generation and mitigate local grid congestion (see full report in section 3.2).
- Collaborate with DSOs and energy suppliers to test dynamic electricity tariffs and flexible load control in real-world settings to build evidence for broader adoption (see full report in sections 4.2 and 4.3).

TSO

- Increase the TSO-DSO coordination to ensure that flexible loads can contribute to relevant system services, increasing the value of flexibility (see full report in sections 2.1 and 2.2).
- Provide transparent information on flexibility needs including location, volume, and time to guide aggregator and energy supplier investments and participation, for example by introducing dynamic, locational transmission grid tariffs (see full report in section 4.2).

DSO / utility

- Adopt flexibility-aware grid infrastructure planning frameworks leveraging end-user flexibility to defer and reduce the need for distribution grid upgrades by (i) shifting and/or reducing the load due to HPs and EV charging, (ii) limiting the PV feed-in, and (iii) taking into account the voltage support provided by PVs (see full report in section 2.2).
- Ensure that the grid models for low voltage networks (i.e., network layer 7) are available for grid simulations to increase the efficacy of flexibility-aware planning frameworks (see full report in section 2.2).
- Offer dynamic grid tariffs as default option (opt-out) for customers with smart meters, and complement these with capacity or peak components when rebound peaks start to emerge to reduce system peaks and lower costs for end-users (see full report in sections 4.2 and 4.3).
- Enable appliance-level direct load control with clear user override options to ensure secure peak shaving without affecting comfort (see full report in section 4.3).
- Provide standard signal interfaces (price signals, control constraints) to aggregators to coordinate flexible load dispatch at scale (see full report in section 4.2).
- Enable or offer PV-feed-in-management options such as feed-in limitation, flexible demand shifting to match peak PV production, and grid-friendly operation of battery energy storage systems to increase end-user self-sufficiency while reducing grid loading (see full report in section 2.2).

Aggregator and energy supplier

- Pass the spot price through to the customers while at the same time protecting their bills through profile contracts to provide efficient incentives for load shifting and energy savings in future energy crises and integrate flexible demand into portfolio management (see full report in section 4.3).

- Offer appliance-level load control with comfort guarantees and user overrides to minimize behavioural burden and improve both the *acceptance of* dynamic price signals and the customer *reaction to* the dynamic price signals (see full report in section 4.3).
- Deploy V1G broadly now and V2G where vehicles, charging infrastructure, and sites meet technical requirements/conditions to expand flexible capacity and monetize EV storage potential (see full report in section 3.2).
- Integrate with wholesale/balancing markets using updated bid formats and standardized DSO/TSO interfaces to coordinate dispatch at scale (see full report in section 4.2).

Technology provider and manufacturer

- Deliver flexibility-ready devices with open standards, local control, and automation to ensure compatibility with future programs and enable flexible operation (see full report in section 4.3).
- Develop interfaces to collect the dynamic tariff signals which are made available by grid operators to overcome current limitations of energy management systems and enable a decentralized, grid-friendly load-dispatch (see full report in section 4.2).
- Develop future proof load-control algorithms, which can optimize dispatch in case of hybrid tariffs that combine dynamic per-kWh charges with different types of per-kWp capacity charges to enable optimal, grid-friendly load-shifting without rebound peaks (see full report in section 4.2).
- Include appliance-level direct control with opt-out automation, comfort settings, and override options to unlock flexibility while preserving user comfort (see full report in section 4.3).
- Offer measurement and control interfaces to enable model-predictive control using price, emissions, and weather signals to improve performance and enable advanced services (see full report in section 3.1).
- Support separately metered flexible loads for dispatch by aggregators or specialized energy providers to increase market access and device value (see full report in sections 3.1 and 3.2).

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