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Zusammenfassung

Zielsetzung und Methodik des Forschungsprojektes

Dieses Forschungsprojekt untersucht verschiedene erneuerbare Energien-Technologien in Bezug auf ihre Fähigkeit, Einnahmen am Markt zu erzielen, beurteilt die Risiken für die Projektträger (Einnahmenverteilung) und schätzt die Notwendigkeit für Fördermechanismen in der Schweiz ab. Zwei Risikokategorien wurden berücksichtigt: langfristige Unsicherheiten im Zusammenhang mit der Entwicklung der europäischen Stromsysteme sowie kurzfristige wetterbedingte Unsicherheiten. Beide Risikokategorien haben einen Einfluss auf die Einnahmen, welche die Betreiber von mit erneuerbaren Energien betriebenen Anlagen von den Märkten erwarten können, und auf die Verteilung dieser Einnahmen. Das Forschungsprojekt beurteilt ausserdem die Auswirkungen der Fördermechanismen für erneuerbare Energien auf die Einnahmen und die Risiken.

Das Projekt basiert auf dem «Artelys Crystal Super Grid»-Modell, welches die Funktionsweise des Stromsystems auf europäischer Ebene für ein vordefiniertes Szenario simuliert. In solch einem Szenario sind der Einsatz der verschiedenen Technologien, die Entwicklung der Nachfrage sowie die Brennstoff- und CO_2-Preise definiert. Forschungsinstitute, private Akteure und öffentliche Institutionen nutzen «Artelys Crystal Super Grid» regelmässig, um Kosten-Nutzen-Analysen (insbesondere für Infrastrukturprojekte), Wirkungsanalysen neuer Regulierungen (Marktkopplung, Resource Adequacy, Kapazitätsmechanismen etc.), Vermögensbewertungen etc. durchzuführen.

Die schweizerischen und europäischen Stromsysteme werden technologiescharf mittels einer «Bottom-up-Darstellung» abgebildet und ihre Funktionsweise wird durch eine Minimierung der Betriebskosten, unter Berücksichtigung der technischen Einschränkungen der Produktionsanlagen, der Erzeugungsprofile der erneuerbaren Technologien, der kurz- und mittelfristigen Strategien für die Verwaltung der Speicherkraftwerke etc. approximiert. Die Simulationen werden für 100 Szenarien (2 langfristige Szenarien, in Kombination mit je 50 Klimaszenarien) und mit stündlicher Auflösung (8760 aufeinanderfolgende Zeitschritte für jedes der 100 Szenarien) durchgeführt.

Mehrwert der Studie

Die Beschreibung des Schweizer Stromsektors im «Artelys Crystal Super Grid»-Modell wurde für diese Studie deutlich erweitert. Insbesondere wurde die Modellierung des Schweizer Wasserkraft-Sektors anhand der neuesten öffentlichen Daten des Bundesamtes für Energie und des Bundesamtes für Statistik verfeinert. Dabei wurden zehn Jahre Produktionsstatistik mit den ursprünglichen 100 Klimaszenarien gekoppelt.

Zudem nutzt das Modell eine explizite Darstellung des europäischen Stromsystems auf Länderebene. Es erwies sich als entscheidend bei der Untersuchung der Einnahmen, welche die Schweizer Stromerzeuger erwarten können, ein europäisches Modell zu verwenden, da die Schweizer Preise hauptsächlich durch die Entwicklung in Europa bestimmt werden. Durch die Berücksichtigung zweier langfristiger Szenarien (aufbauend auf den ENTSO-E-Szenarien), die sich in Bezug auf den jährlichen Bedarf, die Nachfragedynamik, die installierten Kapazitäten, die Brennstoff- und die CO_2-Preise unterscheiden, konnte aufgezeigt werden, dass die Nachbarländer bei der Analyse der Markteinnahmen für die Schweizer Erzeuger eine entscheidende Rolle spielen.

Wichtigste Schlussfolgerungen

Die in diesem Bericht vorgestellten Analysen verdeutlichen in erster Linie, dass die Fähigkeit, an den Märkten Einnahmen zu erzielen, von der jeweiligen Technologie abhängt. In allen Szenarien können bei Grosswasser- und Windkraftwerken höhere durchschnittliche Verkaufspreise erwartet werden als bei Laufwasserkraftwerken und Photovoltaikanlagen. Im

Gegensatz zu Solar- und Laufwasserkraftwerken erzeugen Grosswasserkraft- und Windanlagen tendenziell mehr Strom in Zeiten starker Nachfrage und hoher Preise. Sollten also technologieneutrale Fördermechanismen eingeführt werden, ist zu erwarten, dass die Windenergie attraktiver sein wird als die Photovoltaik, weil sie am Markt höhere Einnahmen zu erzielen vermag.

Wenn man die Einnahmen, welche die einzelnen Technologien 2030 an den Märkten erzielen dürften, mit den angenommenen Fixkosten vergleicht und dabei bestimmte Modellannahmen (insbesondere betreffend Investitionskosten, Brennstoff- und CO_2-Preise) berücksichtigt, zeigt sich, dass sich die Investition in bestimmte Technologien nicht rentiert. So verdeutlichen die im Rahmen dieser Studie durchgeführten Kosten-Nutzen-Analysen, dass die Photovoltaik und die Grosswasserkraft aus Sicht eines Projektträgers, der die erzeugte Energie im Jahr 2030 an den Märkten verkauft, wirtschaftlich nicht rentabel sind. Hingegen generieren die Windenergieanlagen und Laufwasserkraftwerke kostendeckende Einnahmen und sind somit gewinnbringend.

Investitionsentscheidungen beruhen nicht ausschliesslich auf den durchschnittlichen Einnahmen, die ein Projektträger erwarten kann, sondern auch auf deren Verteilung. Diese hängt insbesondere von den Unsicherheiten im Zusammenhang mit der Entwicklung des Stromsektors in Europa und den schwankenden Wetterbedingungen ab. Anhand der Untersuchung unterschiedlicher Zukunftsszenarien konnte die Einnahmenverteilung analysiert und so das von einem möglichen Investor wahrgenommene Risiko sowie die Wirkung dieses Risikos auf die Investitionsentscheidung eingeschätzt werden.

Gemäss unserer Analyse wirken sich die Risiken nur geringfügig auf die Einschätzung der Rentabilität der verschiedenen Technologien aus. Sie haben folglich auch nur einen geringen Einfluss auf den Förderbedarf der unrentablen Technologien. Die Risikoevaluation hat gezeigt, dass sich die Entwicklung der Stromsysteme in den Nachbarländern deutlich stärker auf die Einnahmen auswirkt als die Klimaschwankungen. Es kann deshalb empfohlen werden, dass die zuständigen Schweizer Behörden die Entwicklung und die erwarteten Auswirkungen der europäischer Politikinitiativen und Massnahmen beobachten, um die Eckwerte der Fördermechanismen, die den Erzeugern von Strom aus erneuerbaren Energien in der Schweiz zur Verfügung stehen, auf transparente Weise anpassen zu können.

Ausserdem haben die im Rahmen dieses Forschungsprojekts durchgeführten Analysen gezeigt, dass die Schweiz als «Price Taker» bezeichnet werden kann: Aufgrund der geringen Grösse des Schweizer Stromsystems und den grossen Kapazitäten für den Austausch mit den Nachbarländern hat die Schweiz kaum Einfluss auf die Marktpreisbildung. Deshalb zeigen sich Kannibalisierungseffekte (beispielsweise dadurch, dass Investitionen in Photovoltaikanlagen dazu führen, dass die Markpreise zur Mittagszeit sinken und diese Technologie so weniger attraktiv wird) häufig nur bei als unrealistisch einzustufenden Marktanteilen von Photovoltaik. Dieselbe Schlussfolgerung gilt für die Windenergie. Dieses Ergebnis zeigt deutlich, dass eine Szenarisierung der Entwicklung des europäischen Energiesystems ein zentrales Element für eine glaubwürdige Analyse der Zukunft des Schweizer Stromsystems und seiner Märkte bilden muss.

Diese quantitative Studie basiert auf einer Reihe von Annahmen. Wie bei jeder Modellierung kann eine Änderung der Annahmen die Ergebnisse und die Schlussfolgerungen beeinflussen. Zu den Annahmen, die beobachtet und regelmässig nachgeführt werden sollten, gehören die Investitionskosten. In dieser Untersuchung sind die MW-Kosten aller Projekte einer Technologie gleich, da Kostenkurven für die Schweiz fehlen. In der Praxis weisen verschiedene Projekte allerdings unterschiedliche Kosten auf (beispielsweise wegen des geografischen Standorts, der Anschlusskosten, der Auswahl der Komponenten etc.). Eine Forschungsrichtung, der nachgegangen werden sollte, sind solche Kostenkurven, welche beschreiben, wie sich die Projektkosten in Abhängigkeit der Potentialausschöpfung entwickeln. Der Zugang zu solchen Daten könnte eine gleichzeitige Optimierung des Portfolios erneuerbarer Technologien, dazugehöriger Flexibilitätslösungen und ihres Standorts im Netz ermöglichen.

Die in diesem Bericht ermittelten Werte für die Fördermechanismen basieren auf Kostenprojektionen für das Jahr 2030 und auf Einnahmenschätzungen, die durch Simulationen verschiedener Szenarien für 2030 vorgenommen wurden. Sie entsprechen somit weder den Werten, welche die Fördermechanismen heute, noch denjenigen, die sie während der Lebensdauer des Investitionsvorhabens aufweisen sollten. Die Werte für die Fördermechanismen können nur als Werte interpretiert werden, die sicherstellen, dass die Investitionsprojekte 2030 rentabel sind, ohne vergangene oder künftige Einnahmen zu berücksichtigen. Hingegen tragen sie den Risiken im Zusammenhang mit den Klimaveränderungen und der unsicheren Entwicklung des europäischen Energiesektors Rechnung.

Verschiedene Annahmen, die sich auf die Ergebnisse auswirken können, werden im Folgenden aufgeführt. Allerdings werden die in diesem Bericht vorgestellten Schlussfolgerungen dadurch kaum beeinflusst:

- Es wurde von einer Kopplung der Märkte in Europa ausgegangen. Obwohl der Schweizer Intraday-Markt mit den benachbarten Märkten gekoppelt ist, könnte sich diese Situation künftig verändern.
- Nur die mit dem Energieverkauf an den Märkten verbundenen Einnahmen wurden berücksichtigt. Würden Einnahmen im Zusammenhang mit den Reservemärkten berücksichtigt, könnte dies die Rentabilität bestimmter Technologien, insbesondere der Wasserkraft, beeinflussen.
- Den Anschlusskosten wird in dieser Studie nicht Rechnung getragen.
- Die Auswirkungen der finanziellen Verantwortlichkeit der Produzenten für Differenzen zwischen prognostizierter und realer Erzeugung wird in dieser Studie nicht berücksichtigt. Um diesen Einfluss vollständig zu erfassen, wäre eine detailliertere Darstellung der Produktionseinheiten nötig, da derartige Differenzen unterschiedlicher Erzeugungseinheiten mittels eines entsprechenden Portfoliomanagements kompensiert werden könnten. Zudem hängt dieser Einfluss von den Einzelheiten des Mechanismus für den Ausgleich der Erzeugungsdifferenzen ab.
- In dieser Untersuchung blieben die Opportunitäten im Zusammenhang mit der regionalen Kooperation bei den Fördermechanismen für erneuerbare Energien unberücksichtigt. In solchen Modellen würden zunächst die besten regionale Potenziale genutzt, was zu einem Kostenrückgang führen würde.

Potentielle weiterführende Forschungsrichtungen

Im Rahmen dieses Projekts wurden folgende Forschungsrichtungen identifiziert:

- Eine explizite Darstellung aller Marktsegmente und ihrer dazugehörigen Handelsoptionen (einschliesslich der Art und Weise, wie Akteure ihre Positionen anpassen, wenn sie neue Informationen mit verminderten Prognosefehlern erhalten) könnte genutzt werden, um insbesondere unterschiedliche Biet-Strategien genauer zu untersuchen.
- Die Folgen des jüngsten Rückgangs der Kosten für erneuerbare Energien könnten untersucht werden, insbesondere um zu verstehen, ob es technisch und wirtschaftlich möglich ist, über die in dieser Studie in Betracht gezogenen Ziele hinauszugehen. Eine gemeinsame Optimierung der erneuerbaren Energien und der Flexibilitätslösungen (Netz, aktives Nachfragemanagement, Speicherung, Spitzenlasteinheiten) wäre für die Entscheidungsgremien von grossem Nutzen.

- Ebenfalls von grossem Wert wäre ein Multi-Energie-Ansatz für die Optimierung des Energiesystems der Schweiz. Mit einem solchen Ansatz wäre es möglich, die Synergien zwischen Strom-, Gas- und Wärmenetzen zu erkennen und zu nutzen.
- Eine Analyse der dynamischen Effizienz der Fördermechanismen für erneuerbare Energien (d. h. Auswirkung der Unterstützung auf den allmählichen Kostenrückgang dieser Technologie) wäre von Interesse, um den unterschiedlichen Lernkurven der verschiedenen Technologien (wegen der Entwicklung von lokalem industriellem Fachwissen für bestimmte Technologien) Rechnung zu tragen.

Résumé exécutif

Objectifs et méthodologie du projet de recherche

Les objectifs de ce projet de recherche sont d'établir la capacité de différentes technologies exploitant des sources d'énergie renouvelable à capter des revenus de marché, d'évaluer les risques associés pour les promoteurs de projets (dispersion des revenus), et d'estimer le besoin de mécanismes de soutien en Suisse. Deux catégories de risques ont été prises en compte : des incertitudes de long-terme liées à l'évolution des systèmes électriques européens et des incertitudes de court-terme liées aux conditions météorologiques. Ces deux catégories de risques influencent les revenus que les opérateurs de centrales renouvelables peuvent attendre des marchés ainsi que la dispersion de ces revenus. Les impacts des mécanismes de soutien aux énergies renouvelables sur les revenus et risques sont également évalués.

Le projet repose sur le modèle Artelys Crystal Super Grid, qui permet de simuler le fonctionnement du système électrique à l'échelle européenne en se basant sur un scénario de déploiement des technologies et d'évolution de la demande, des prix de combustibles et de CO_2. Artelys Crystal Super Grid est régulièrement utilisé par des instituts de recherche, des acteurs privés ainsi que des institutions publiques pour réaliser des analyses cout-bénéfice (en particulier pour les projets d'infrastructure), des analyses d'impact de nouvelles régulations (couplage des marchés, resource adequacy, mécanismes de capacité, etc.), des évaluations de valeur d'actifs, etc.

Le fonctionnement des systèmes suisse et européens sont obtenus en minimisant les coûts opérationnels dans une représentation « bottom-up » tout en prenant en compte les contraintes techniques s'appliquant aux centrales de production, les profils de production des technologies renouvelables, les stratégies de court et moyen terme de gestion des stocks hydrauliques, etc. Les simulations sont réalisées sur 100 scénarios (2 scénarios de long-termes, chacun couplé avec 50 scénarios climatiques) en utilisant une résolution horaire (8760 pas de temps consécutifs pour chacun des 100 scénarios).

Valeur ajoutée

La description du secteur électrique suisse d'Artelys Crystal Super Grid a considérablement été enrichie. En particulier, les dernières données publiques disponibles de l'Office Fédéral de l'Energie et de l'Office Fédéral des Statistique ont été utilisées pour affiner la modélisation du secteur hydraulique suisse. Durant cette calibration, 10 ans de statistiques de production ont été couplées avec les 100 scénarios climatiques originaux.

De plus, le modèle fait usage d'une représentation explicite du système électrique européen, à la maille pays. Adopter un modèle européen lors de l'étude des revenus que peuvent attendre les producteurs suisses s'est relevé crucial étant donné que les prix suisses sont principalement dictés par la dynamique européenne. La considération de deux scénarios de long-terme (basés sur des scénarios de l'ENTSO-E), qui diffèrent en termes de demande annuelle, dynamique de la demande, capacités installées, prix des combustibles et du CO_2, a permis de mettre en lumière le rôle crucial que jouent les pays voisins lors de l'analyse des revenus de marché pour les producteurs suisses.

Principales conclusions

Les analyses présentées dans ce rapport montrent en premier lieu que la capacité à capter des revenus sur les marchés dépend de la technologie. Dans tous les scénarios, les prix de vente moyens que peuvent espérer les grandes unités hydrauliques ainsi que l'éolien sont supérieurs à ceux des centrales au fil de l'eau et du solaire photovoltaïque. En effet, ces technologies tendent à produire plus lors d'épisodes de forte demande et de prix élevés, contrairement au solaire et fil de l'eau.

Lorsque les revenus captés sur les marchés en 2030 sont comparés aux hypothèses de coûts fixes des différentes technologies considérées, et sous les hypothèses retenues (notamment relatives aux coûts d'investissement, prix des combustibles et du CO_2), il s'avère que certaines technologies ne sont pas rentables. En effet, les analyses coût-bénéfice réalisées lors de cette étude révèlent que le solaire photovoltaïque et la grande hydraulique ne sont pas économiquement rentables du point de vue d'un porteur de projet vendant la production sur les marchés en 2030. Toutefois, l'éolien ainsi que l'hydraulique au fil de l'eau génèrent des revenus leur permettant de couvrir leurs coûts et ainsi d'être rentables. En conséquence, si des mécanismes de soutien technologiquement neutres devaient être mis en place, on peut anticiper que l'éolien serait plus attrayant que le solaire photovoltaïque en raison de sa meilleure capacité à capter des revenus de marché plus élevés.

Les décisions d'investissement ne reposent pas entièrement sur la moyenne des revenus qu'un promoteur peut espérer, mais également sur la dispersion de ces revenus, notamment étant données les incertitudes liées à l'évolution du secteur électrique européen et aux variations de conditions météorologiques. A partir de l'étude de scénarios futurs contrastés, l'analyse de la dispersion des revenus a permis l'évaluation du risque perçu par un potentiel investisseur et l'impact de ce risque sur la décision d'investissement.

Selon notre analyse, les risques n'ont qu'un faible impact sur la perception de rentabilité des différentes technologies considérées et n'impactent dès lors que peu le montant du soutien nécessaire pour les technologies non-rentables. L'évaluation des risques a démontré que l'évolution des systèmes électriques dans les pays voisins influence bien plus les revenus que la variabilité des conditions climatiques. Il peut dès lors être recommandé que les autorités suisses observent le développement et les impacts attendus des politiques et mesures européennes, afin d'être en mesure d'adapter de manière transparente les paramètres des mécanismes de soutien mis à disposition des producteurs d'énergie renouvelable en Suisse.

De plus, les analyses conduites lors de ce projet de recherche ont montré que la Suisse peut être caractérisée comme « price taker » : la taille du système électrique suisse et ses importantes capacités d'échange avec les pays voisins sont telles que la Suisse n'a que peu d'influence sur la formation des prix de marché. Dès lors, les effets de cannibalisation (par exemple dus au fait qu'investir dans des centrales photovoltaïques a tendance à faire baisser les prix de marché en milieu de journée, et, conséquemment, à réduire l'attractivité de cette technologie) ont tendance à n'apparaitre que pour des pénétrations de solaire photovoltaïque que l'on peut qualifier d'irréalistes. La même conclusion est valide pour l'énergie éolienne. De façon cruciale, cette conclusion montre qu'une scénarisation de l'évolution du système énergétique européen se doit d'être l'un éléments centraux d'une analyse crédible du futur du système électrique suisse et de ses marchés.

Cette étude quantitative repose sur un certain nombre d'hypothèses. Comme lors de tout exercice de modélisation, un changement d'hypothèse peut impacter les résultats ainsi que les conclusions. La catégorie d'hypothèse nécessitant d'être observée et régulièrement mise à jour concerne les coûts d'investissement. Dans cette étude, en l'absence de « cost curves » pour la Suisse, tous les projets d'une technologie donnée ont un coût par MW identique. Toutefois, en réalité, différents projets ont différents coûts (par exemple en raison de l'emplacement géographique, des coûts de raccordement, du choix des composants, etc.). L'adoption de « cost curves » décrivant comment les coûts des projets évoluent au fur et à mesure de l'exploitation du potentiel est une direction de recherche à privilégier. En effet, l'accès à de telles données pourrait rendre possible l'optimisation conjointe du portefeuille de technologies renouvelables, des solutions de flexibilité ainsi que de leur emplacement sur le réseau.

Il doit aussi être noté que les valeurs des mécanismes de soutien calculés dans ce rapport sont basées sur des coûts projetés à l'horizon 2030 et sur des estimations des revenus via des simulations de plusieurs scénarios 2030. Elles ne reflètent donc ni les valeurs que les mécanismes de soutien devraient prendre aujourd'hui ni celles qu'elles devraient prendre tout au long de la durée de vie du projet d'investissement. Les valeurs des mécanismes de soutien ne peuvent qu'être interprétées comme étant telles que les projets d'investissements soient rentables en 2030, sans prendre en compte les revenus passés ou futurs, mais en prenant en compte les risques liés aux variations climatiques et aux incertitudes liées à l'évolution du secteur énergétique européen.

Un certain nombre d'hypothèses pouvant avoir un impact sur les résultats sont présentées ci-dessous. Toutefois, les conclusions présentées dans ce rapport n'y sont que modérément sensibles:

- Hypothèse a été faite que les marchés sont couplés en Europe. Bien que la Suisse soit couplée en intraday avec les marchés voisins, cette situation pourrait évoluer dans le futur.
- Seuls les revenus liés à la vente d'énergie sur les marchés ont été pris en compte. Considérer les revenus liés aux marchés de la réserve pourrait impacter la rentabilité de certaines technologies, notamment hydrauliques.
- Les coûts de raccordement ne sont pas pris en compte dans cette étude.
- L'impact de la responsabilité financière pour les écarts entre production et consommation générés par les producteurs d'énergies renouvelables au sein d'un groupe bilan n'est pas présenté dans cette étude. Afin de pleinement capter cet impact, une représentation plus détaillée des unités de production serait nécessaire pour prendre en compte les compensations entre unités au sein d'un portefeuille. De plus, cet impact dépend des détails du mécanisme de règlement des écarts.
- Les opportunités liées à la coopération régionale au niveau des mécanismes de soutien aux énergies renouvelables n'ont pas été considérés dans cette étude. Dans de tels schémas, les meilleurs potentiels au niveau régional seraient exploités en premier, ce qui résulterait en une baisse des coûts.

Directions de recherche

Les directions de recherche suivantes ont été identifiées lors de ce projet :

- Une représentation explicite de tous les guichets de marché (incluant la manière dont les acteurs affinent leurs positions lors de l'acquisition de nouvelles informations) pourrait être exploitée, en particulier en lien avec les stratégies de bidding.
- Les conséquences de la réduction récente des coûts des énergies renouvelables pourraient être explorées, en particulier afin de comprendre s'il est techniquement et économiquement faisable d'aller au-delà des objectifs considérés dans cette étude. Une optimisation conjointe des énergies renouvelables, des solutions de flexibilité (réseau, gestion active de la demande, stockage, unités de pointe) aurait une valeur ajoutée importante pour les organes de décision.
- Une approche multi-énergie de l'optimisation du système énergétique Suisse serait également de grande valeur. En effet, une telle approche pourrait détecter et exploiter les synergies entre les réseaux d'électricité, gaz et chaleur.
- Une analyse de l'efficacité dynamique des mécanismes de soutien des énergies renouvelables (i.e. l'impact du support sur le déclin graduel des coûts de cette technologie) serait des plus intéressantes, étant donné que différentes technologies sont susceptibles d'avoir des courbes d'apprentissage différentes (notamment en raison du développement d'une expertise industrielle locale pour certaines technologies).

Executive summary

Objectives and methodology of the research project

The objectives of this research project are to assess the ability of different renewable technologies to capture market revenues, to evaluate the associated risks for project promoters (dispersion of revenues), and to estimate the need for support schemes in Switzerland. Two categories of risks have been considered: long-term risks related to the uncertain evolution of the European power systems and risks related to weather conditions. Both categories of risks influence the market revenues that can be expected by renewable power producers and the dispersion of these revenues. Finally, we evaluate the impact of renewable support schemes on revenues and risks.

The project relies on the Artelys Crystal Super Grid model, which allows for a simulation of the operations of the power system across Europe for a given set of assumptions on capacity mix, demand levels and fuel and CO_2 prices. Artelys Crystal Super Grid is regularly used by academics, consultants, market players and public authorities to perform cost-benefit analyses (in particular for infrastructure projects), market design impact assessments (e.g. market coupling, resource adequacy assessment methodology, capacity mechanisms, etc.), asset valuation, etc.

The operations of the Swiss and European power systems are obtained by minimising the operational costs using a bottom-up representation of the system and taking into account technical constraints of generation assets, renewable generation profiles, seasonal and short-term hydro storages, etc. The simulations are performed for 100 scenarios (2 long-term scenarios, each being coupled with 50 weather scenarios) with an hourly time resolution (8760 consecutive time-steps for each of the 100 scenarios).

Added value

For this study, the description of the Swiss power sector in Artelys Crystal Super Grid has been considerably enriched. In particular, the latest publicly available datasets from the Swiss Federal Office of Energy and Swiss Federal Office of Statistics have been used to refine the description of the Swiss hydropower sector. In particular, 10 years of production statistics have been coupled with our original weather scenarios.

Furthermore, the model uses an explicit representation of the European power system, at the country level. This proves to be of great value when assessing the revenues of the different market players, as the wholesale electricity prices in Switzerland are mostly driven by the European context. Considering 2 long-term scenarios for Europe (based on ENTSO-E scenarios), which differ in terms of annual demand, demand dynamics, installed capacities, fuel and CO_2 prices has allowed us to highlight the crucial role of neighbouring countries when analysing the market revenues of Swiss power producers.

Main conclusions

The analysis presented in this report shows that the ability to capture revenues on the market depend on the technology. In all scenarios, we find that the average selling prices of large hydro and wind power is higher than those of hydro run-of-the-river and solar PV, since these technologies tend to produce during high-demand episodes.

When comparing the 2030 wholesale market revenues to the assumed fixed costs of the different considered technologies, and under our assumptions (in particular regarding capital expenditure and the fuel and CO_2 price), we find that some technologies are not profitable. Indeed, the cost-benefit analysis carried out during this project has revealed that solar PV and large hydro are not profitable under our central cost assumption from the point of view of a project promoter selling the generated energy on the electricity market in 2030. On the other hand, we find that wind power and run-of-the-river units are able to capture sufficient revenues to recover their costs. As a consequence, we can anticipate that if technologies were to be supported through a technology-neutral fixed market premium, wind power would be more attractive than solar PV installations.

As an investment decision is not only based on the expected level of revenues, we have analysed the distribution of these revenues when one considers contrasted but possible scenarios of the evolution of the European power sector and a range of weather scenarios. The dispersion of the distribution of revenues has allowed us to evaluate the risks attached to investment projects, and the impact of this risk on the investment decision.

According to our analysis, the risks have a low impact on the perceived profitability of the considered technologies and therefore do not impact much the required support for unprofitable technologies. The evaluation of the risks has demonstrated that the evolution of the European power sector has a much greater influence on revenues over the lifetime of an investment than the weather variability. This fact advocates for a regular monitoring of the development and expected impacts of European policies and measures, so as to be able to transparently review the parameters of the Swiss support schemes.

Furthermore, the analysis conducted during this project has shown that Switzerland can be characterised as a price-taker: the size of its power system and the strong level of interconnection with neighbouring countries are such that Switzerland only has a very limited influence on market clearing prices. As a consequence, the cannibalisation effect (the fact that further investments in solar PV tend to decrease market prices around midday and, as a consequence, to decrease the attractiveness of solar PV) is found to only appear for unrealistic shares of solar PV. The same conclusion has been reached for wind power. More critically, this means that a credible scenarisation of the evolution of the European power system markets should be one of the central elements of any analysis of the future of the Swiss power sector.

This study is based on a number of assumptions. As is the case of all modelling exercises, changing some of these can have a material impact on the results and the conclusions. The most important category of assumptions that should be closely monitored and regularly updated when dimensioning support levels is the capital expenditure (investment costs). In this study, we have assumed, in the absence of cost curves for Switzerland, a single investment cost per technology. In reality, different projects have different costs (e.g. due to location, grid connection costs, choice of components, etc.). Adopting cost curves that describe how more expensive projects become as one gradually exploits the best options would be a direction for future research, and could lead to interesting results in terms of optimal portfolio of technologies and, potentially, optimal localisation of these technologies on the Swiss power grid.

One should also note that since the computed support values are based on projected 2030 investment costs and on market revenues derived from simulations of several 2030 scenarios, they neither reflect the current value of the support schemes nor the value they should have all along the lifetime of the project. The computed support values can thus only be interpreted as the level of supports that allows the considered assets to be profitable in 2030. The support values are not influenced by the past or future revenues, but take into account the risks related to the variability of weather conditions and to the uncertainty related to the evolution of the European energy sector.

Other assumptions that can have an impact on the results are listed below. However, the conclusions presented herein should not be significantly impacted by these assumptions:

- We have assumed that markets are coupled over the whole of Europe. Although Switzerland and its neighbours are currently coupled in the intraday markets, this situation could change in the future.

- We have only considered the revenues generated by selling electricity on the energy markets. Considering the revenues from the provision of ancillary services could impact the profitability of the considered technologies, in particular of hydropower.
- Grid connection costs are outside the scope of this study.
- The impact of balancing responsibility are not presented in this study. In order to fully capture this impact a more detailed representation of the units would be necessary, as imbalances could be compensated for through an optimal portfolio management. Furthermore, the impact of balancing responsibility for RES producers depends on the details of the design of the financial settlement of imbalances (for which the RES producers can either be charged by or paid by the TSO, depending on the direction of their imbalance compared to the imbalance price area imbalance).
- We have not considered regional cooperation mechanisms for RES support. Such mechanisms would lead to a different distribution of RES generation in the cooperating countries as the best potentials would be exploited first.

Directions for future research

The following directions for future research have been identified during this project:

- An explicit representation of all market timeframes (including how positions are refined as market participants obtain more information due to the reduction of forecast errors) could be exploited, in particular to investigate the impact of bidding strategies.
- The recent decline of RES costs advocate for an analysis of the technical and economic feasibility of a power system with more RES that the one considered in this study. A joint optimisation of RES installed capacities and flexibility solutions (network, demand-response, storage, mid-merit and peak thermal generation) would have a high value for policy makers.
- A multi-energy approach to the optimisation of the Swiss energy system would be valuable, as it could detect and exploit synergies between the electricity, gas and heat systems.
- An analysis of the dynamic efficiency of the RES support schemes (i.e. the impact of the support on the gradual price decline of the technologies) would be interesting, as different technologies are likely to behave differently (since the dynamic efficiency is in particular linked to the development of a local industrial expertise).

Acronyms

CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CFD	Contract For Difference
CO_2	Carbon dioxide
CRM	Capacity Remuneration Mechanism
EPFL	Ecole Polytechnique Fédérale de Lausanne
ETS	European CO_2 Trading Scheme
ENTSO-E	European Network of Transmission System Operators for Electricity, representing 43 TSOs from 36 countries across Europe
EOM	Energy-Only Market, by opposition to markets with Capacity Remuneration Mechanisms
FIP	Feed-In Premium
FIT	Feed-In Tariff
IAEW	Institut für Elektrische Anlagen und Energiewirtschaft of Aachen University
IEA	International Energy Agency
JRC	Joint Research Centre of the European Commission
METIS	Mathematical model providing analysis of the European energy system for electricity, gas and heat. Developed by a consortium led by Artelys for the European Commission
MW	Megawatt, unit of power
MWh	Megawatt hour, unit of energy
NTC	Net Transfer Capacity
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditure
PHS	Pumped Hydro Storage
PV	Photovoltaic panels
RES	Renewable Energy Sources
ROR	Hydro Run Of the River
SES	Swiss Energy Strategy
SFOE	Swiss Federal Office of Energy
TSO	Transmission System Operator
TYNDP	ENTSO-E's Ten-Year Network Development Plan
VOLL	Value Of Lost Load
WEO	IEA's World Energy Outlook

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1. Project Overview

This section provides an overview of the project by setting out the context, both in terms of Switzerland's medium- to long-term energy/climate strategy and in terms of support schemes to incentivise project developers to invest in technologies relying on renewable energy sources (RES).

a. Context

Switzerland and the energy transition

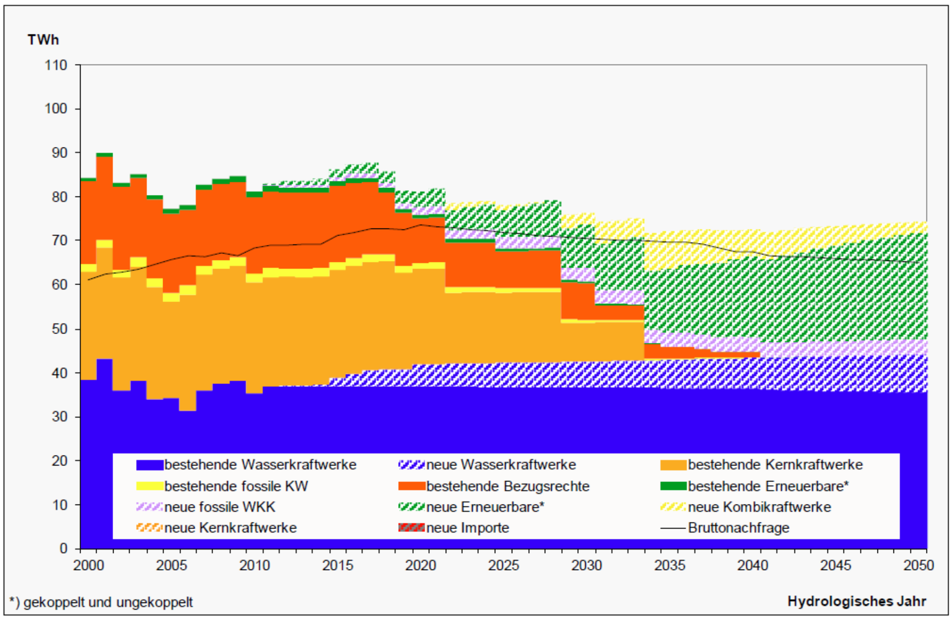
The Swiss Energy Strategy 2050, elaborated by the Swiss Federal Council [1], aims at defining a pathway to the 2050 horizon towards a nuclear-free and partially decarbonised energy mix. A few months after the Fukushima-Daiichi nuclear disaster in May 2011, the Federal Council decided to gradually phase-out nuclear power, by forbidding the replacement of existing nuclear reactors after their safe operational lifespan [2]. The first package of measures of the Energy Strategy 2050 was accepted by the Swiss people on May 21st 2017 [3]. Moreover, Switzerland has ratified the Kyoto protocol in 2003, and has set in the objective of reducing its greenhouse gas emissions by 20% compared to 1990 levels, by 2020 [4]. Finally, the Swiss parliament has recently accepted to ratify the Paris Climate Accord [5] under which, via its Intended Nationally Determined Contribution (INDC), Switzerland has committed to a 50% reduction of its greenhouse gas emissions by 2030 compared to its 1990 level [6].

In order to ensure a secure, affordable and sustainable energy supply to Switzerland, the Swiss Energy Strategy 2050 strongly relies on efforts in terms of energy efficiency and on the deployment of locally available renewable energy sources [1, 7]. More precisely, as stated in the Energiegesetz law [8], the Swiss Energy Strategy 2050 aims at:

- achieving a 43% reduction of the per capita final energy consumption and a 13% reduction of the per capita electricity consumption compared to the 2000 consumption levels by 2035.
- generating more than 11 400 GWh of renewable electricity by 2035, based on new renewable energy sources (excluding hydropower).

Both these objectives are reflected on Figure 1, which presents the expected evolution of the various electricity generation technologies in the coming decades according to the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario of the Energy Strategy 2050 [7].

Figur 3-4: Sensitivität 1, Szenario „Neue Energiepolitik", Perspektiven der Elektrizitätsversorgung, hydrologisches Jahr, in TWh_{el}/a



Quelle: Prognos 2013

Figure 1. Electricity generation and gross consumption from 2000 to 2050 in the scenario Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1 [7]

By 2050, most of the Swiss electricity production technologies will be exploiting renewable energy sources thanks to a considerable deployment of various new RES technologies photovoltaics (PV), wind turbines, bioenergy, small-scale hydropower and geothermal energy.

RES support schemes

Currently, the deployment of solar PV and wind power largely relies on subsidies, as the costs of these technologies are too high for such projects to be profitable if they were to only be remunerated via market revenues (these technologies have not yet reached grid parity[1]).

The costs of these technologies are expected to continue to decline at a steady pace thanks to cost reductions at the level of the individual components, but also in terms of maturity (e.g. more efficient wind turbines or solar cells) and maintenance procedures. Indeed, both technologies benefit from steep price-experience curves as is illustrated below in the case of wind power and solar PV modules.

---

[1] *Grid parity* is said to be reached when a renewable energy source (solar PV, wind power) can generate power at a levelised cost of electricity (LCOE) that is less than the average wholesale market. *Socket parity* is said to be reached when a renewable energy source can generate power at a levelised cost of electricity that is less than the average retail price.

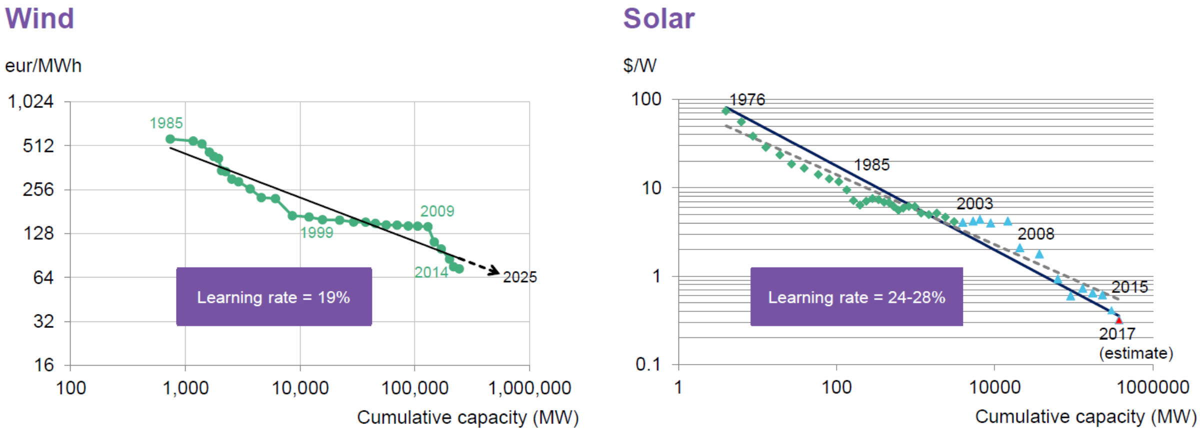


Figure 2. Price-experience curves for wind power and solar PV modules (Source: Bloomberg New Energy Finance, 2017)

One should however note at this stage that Switzerland will most probably benefit from limited economies of scale resulting from investments in large wind farms as the potential and public acceptance for such installations are rather limited, but will still benefit from cheaper wind turbine components (driven by the worldwide development of wind power). The following graph presents the decline of the investment costs of 30 kW solar PV panels in Switzerland.

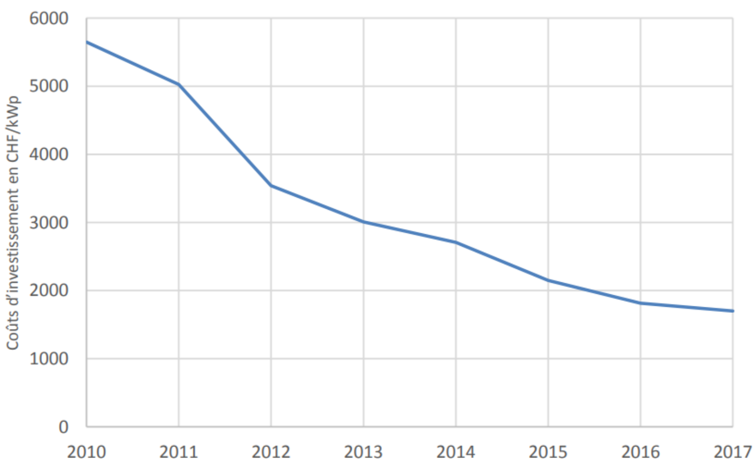


Figure 3. Evolution of the investment costs for solar panels in Switzerland (Source: Swiss Federal Office of Energy, Faktenblatt "Energieversorgung der Schweiz und internationale Entwicklung", 2017)

The following figure presents the improvements in terms of efficiency of solar cells. The combination of the increased efficiency and the reduction of the cost of individual components drive the price decline of PV modules[2].

[2] One should note that an increased efficiency does not automatically translate into a lower LCOE, as the gains in terms of efficiency can be counterweighted by additional costs in terms of manufacturing.

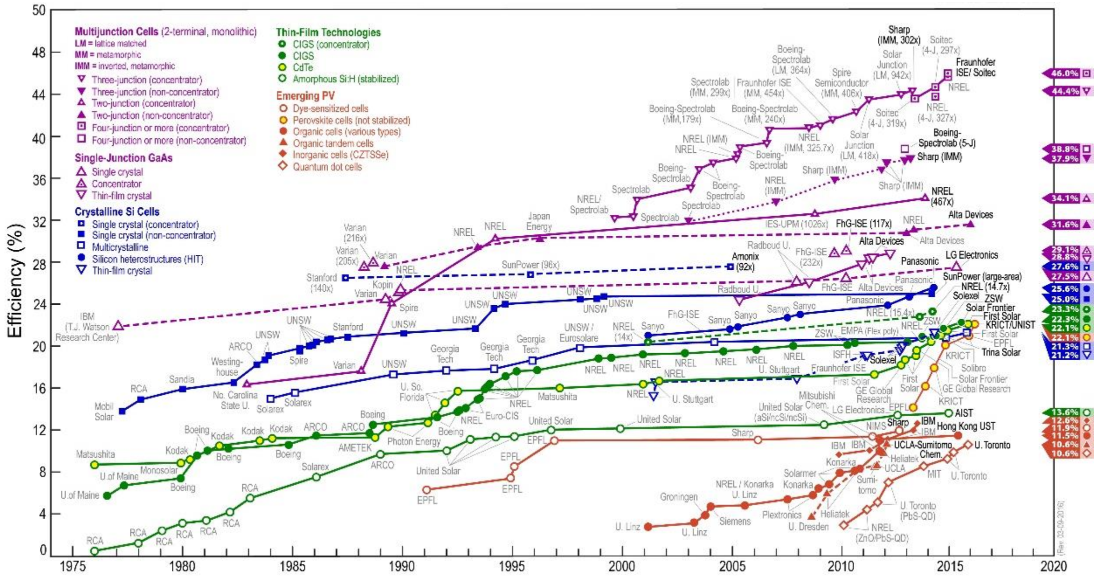


Figure 4. Evolution of the efficiency of solar cells (Source: NREL)

In order for RES technologies to become financially profitable for a producer selling the generated electricity on the market, and for support schemes to be progressively phased-out, the market revenues have to become more important than the costs (investment, variable costs, operations and maintenance, etc.). Two phenomena driven by different underlying dynamics should therefore be taken into account:

- **The evolution of investment costs –** For technologies such as solar PV or wind turbines, the prices of installed capacities can significantly vary from one country to the other. Indeed, even if the hardware prices are very similar worldwide, the heterogeneity of legal requirements, licencing arrangements, grid connection costs, level of wages, level of competition between installers, etc. can results in very different prices of installed systems.
- **The evolution of market prices –** If RES technologies are to become economically viable from the point of view of the producer (i.e. profitable), they have to generate an appropriate level of market revenues, which are influenced by a variety of factors: the evolution of the generation mixes in Europe as most markets are (at least physically) coupled, the demand levels (e.g. in the case of an economic crisis, the demand tends to decrease, leading to lower wholesale electricity prices; the opposite phenomenon could occur in case of a sudden electrification of heat or mobility), the primary energy prices (uranium, gas, coal, biomass, etc.) and the CO_2 price. One should here understand markets as all the markets which can be accessed by RES producers: day-ahead market, intraday market, capacity market, ancillary services, etc.

Although investment costs have been declining rapidly, new RES technologies have not yet reached grid parity in most markets: their costs (e.g. measured by their LCOE) are on average higher than the wholesale market prices. However, socket parity has been reached in a number of regions for domestic PV installations: producing electricity with a domestic PV installation can be cheaper than buying electricity from retailers. In other words, the LCOE can be lower than the retail price of electricity for end-users (wholesale price to which a number of taxes are added: transmission and distribution network taxes, environmental/energy policy taxes, etc.), which incentivises the development of self-consumption practices.

According to the UBS Chief Investment Office, the average retail price of electricity is around 175 €/MWh in Switzerland, as shown below, which is of the order of magnitude of the LCOE of solar PV panels[3].

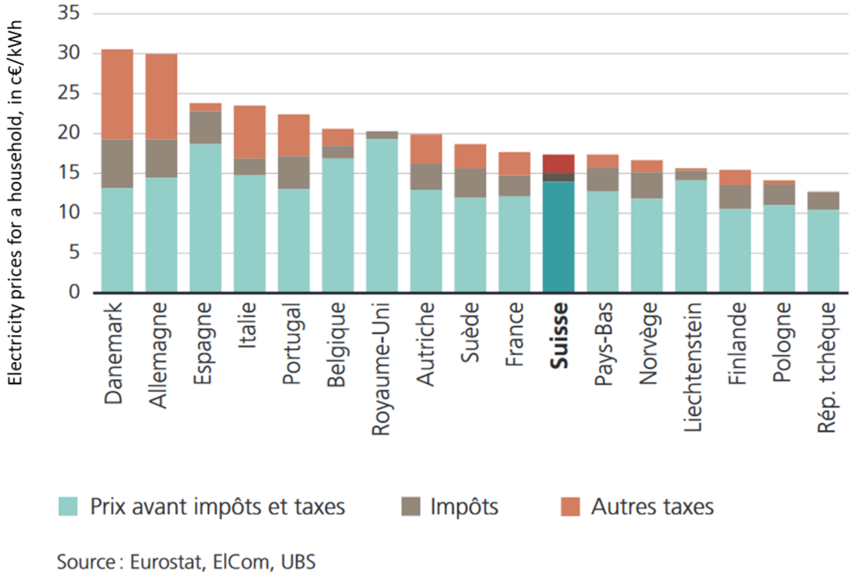


Figure 5. Average 2016 electricity retail prices (Source: UBS, « De nouvelles énergies pour la Suisse », 2016).

As RES technologies are not yet viable if their only revenues are coming from the electricity markets, policy makers have implemented different instruments so as to support the deployment of renewable energy sources in order to reach energy/climate targets (e.g. in terms of carbon intensity of electricity production).

The policy instruments that have been introduced in different countries to support RES over the last decades vary significantly in their design:

- In most support schemes, either the price or the volume of RES production is fixed. In price-based support schemes, the level of support is fixed administratively (e.g. by evaluating representative CAPEX, O&M costs, variable costs, and translating them into a support level in €/MWh), while in volume-based support schemes, it is the production target that is administratively determined (e.g. annual production in TWh). Support can then be granted according to a variety of criteria or through auctions over a fixed time horizon (to limit the policy costs by revising and adapting the targets).
- Support levels are in most cases different for different technologies (and sub-technologies via the size of the project) and sites to reflect the different techno-economic conditions in which they operate. Technology-neutral support schemes are mostly used with volume-based policy instruments, and are favoured by the European Commission (see e.g. [9]).
- In most of the recently introduced RES support schemes, RES producers have to sell their electricity on the markets (and earn the corresponding revenues), while support schemes are used as an additional source of remuneration which can be subject to conditions. The precise design of the support schemes (e.g. a fixed premium per MWh, a premium per MWh with a cap and a floor, etc.) results in different risk allocations between project promoters and the public. Moreover, being exposed to market prices can incentivise a virtuous behaviour by encouraging production during the high demand

[3] An investment cost of 1800 CHF per kW (see Figure 3) correspond to annuities of around 127 500 €/MW/year (4% discount rate, over 25 years, with no residual value) or 144 €/MWh (using 884 full load hours for solar PV).

episodes (i.e. high prices periods). In some cases, market exposure can also incentivise investments in storage units (e.g. solar PV with battery)

- In some countries, RES producers are not financially responsible for their imbalances. In such a case, the costs caused by deviations from the programme communicated by the plant operator to the system operator (e.g. during the intraday market) is borne by the public. As the share of RES increases rapidly, it is likely that RES producers will have to be subject to balancing responsibilities in most European countries.
- Finally, different grid connection arrangements can be implemented to favour the deployment of renewables. In most cases one can either consider deep or shallow connection charges: in the first case the RES project promoter bears grid connection and upgrading costs, while in the second case it only bear grid connection costs (the upgrading costs are borne by the public through the network operator).

The high degree of heterogeneity in the design of support schemes (in particular in terms of grid connection costs) should be taken into account when comparing the results of recent RES auctions. Some of these auctions indicate that although the need for support decreases, RES support schemes are still essential to incentivise investments in RES technologies such as wind and solar PV, as illustrated by the figure shown below.

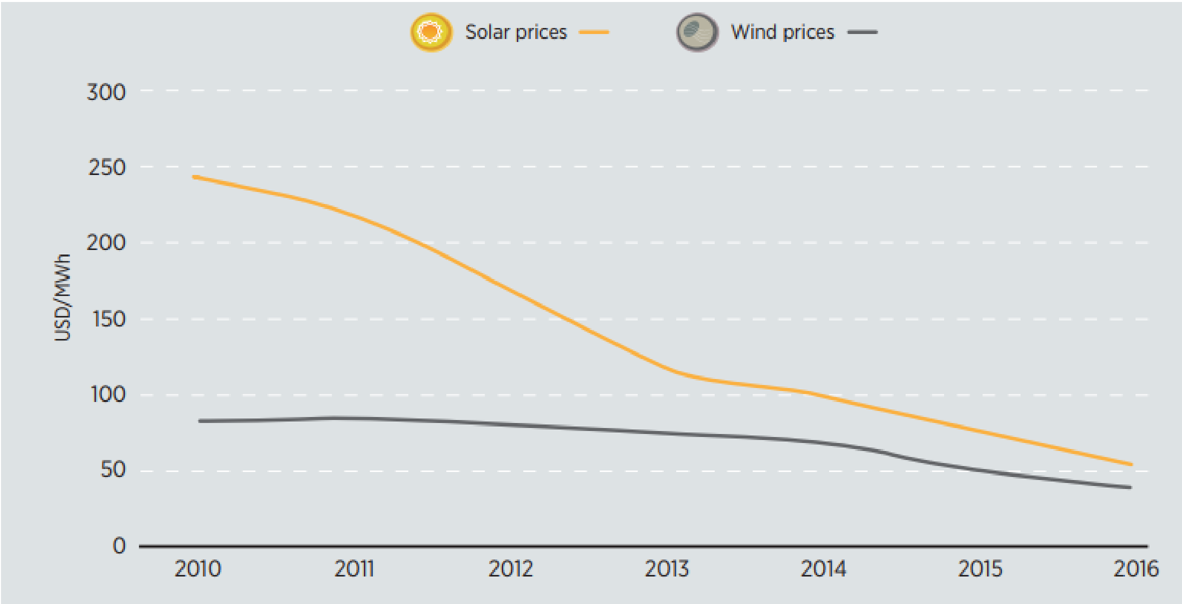


Figure 6. Average prices resulting from auctions, see source for precise definition of the scope (Source: IRENA, Renewable Energy Auctions, 2017)

Finally, already well-established technologies such as large hydro dams or run-of-the-river units may also be needing financial support. Their ability to capture market revenues can be altered by the poor market conditions prevailing in Europe, leading to potential financial difficulties. This is typically the case in Switzerland.

b. Objectives and methodology

The prime objective of this research project is to model the behaviour of potential investors in renewable electricity generation depending on the level of wholesale market prices and of the support schemes. The objective is to quantify the effectiveness of support schemes to mitigate the risks felt by a RES producer so that the RES targets specified in the Swiss Energy Strategy are met.

The approach taken is first to assess the economic profitability and risks of a RES generation source (solar photovoltaic panels, large scale wind turbines, run-of-the-river units or large hydro dams) who sells its electricity in the wholesale market.

To this end, a simulation of the hourly operations of the Swiss power sector in 2030[4] has been performed for 50 different annual weather scenarios (which influence the demand, the RES production, the hydro inflows) and for two long-term evolutions of the European power sector (embedding assumptions on fuel costs level, energy efficiency and energy mix). The hourly electricity prices in the day-ahead markets are estimated by computing the shadow price of the hourly demand-supply equilibrium.

We then evaluate how the different support schemes can affect the risk structure and how they need to be dimensioned in order to provide potential investors with the appropriate price signals to encourage the deployment of these technologies.

The risks that are considered in this research project include the electricity price volatility (through weather patterns), annual production volume variability (through weather scenarios), and average electricity price uncertainty (through long-term scenarios).

Finally, we have assessed how different support schemes (investment aid, feed-in tariff, feed-in premium, feed-in premium with cap and floor, and technology-neutral feed-in premium) should be dimensioned so as to provide investments signals to project promoters. These support schemes are described in detail in section 4.b.

One should also note that since the computed support values are based on projected 2030 investment costs and on market revenues derived from simulations of several 2030 scenarios, they neither reflect the current value of the support schemes nor the value they should have all along the lifetime of the project. The computed support values can thus only be interpreted as the level of supports that allows the considered assets to be profitable in 2030. The support values are not influenced by the past or future revenues, but take into account the risks related to the variability of weather conditions and to the uncertainty related to the evolution of the European energy sector.

c. Organisation of the document

The present document is organised as follows:

- **Section 2** is dedicated to the description of the model and its assumptions, including the exploited datasets, and the optimisation process.
- **Section 3** describes the methodology used for assessing the market revenues of RES generators and highlights the variability in revenues depending on the long-term context and weather variations.
- **Section 4** focuses on the quantification of risk for the producer and the evaluation of support schemes needed to ensure harmonious deployment of RES. A sensitivity analysis presents the impact of cost assumptions on the results.
- **Section 5** finally looks at the revenues of assets through a sensitivity analysis to the capacity of renewables in the Swiss electricity mix.
- **Section 6** presents our conclusions.

[4] Based on the *NEP scenario* for demand and the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario for supply.

2. Modelling assumptions

This section is devoted to the presentation of the main modelling assumptions used in our study.

In particular, we describe how the Artelys Crystal Super Grid model has been configured, based on public data from both Swiss and European sources (e.g. SFOE, Swiss Grid, ENTSO-E and the Joint Research Centre of the European Commission), to represent accurately the 2030 Swiss and European power systems.

We also show how the parameters driving the uncertainties impacting the generation dispatch and producer revenues are taken into account.

The way the model presented in this section is actually used to evaluate the market revenues of Swiss RES technologies is described in Section 3.

a. Modelling Switzerland's power system

i. Simulation of the power dispatch

The behaviour of the Swiss and European power system is simulated using the modelling and optimisation software **Artelys Crystal Super Grid**. The Artelys Crystal Super Grid platform allows to model power systems by explicitly representing production, consumption, interconnection, storage, and demand-response assets. The behaviour of the power system is obtained by maximising the social welfare (or minimising overall production costs), while satisfying the supply-demand equilibrium at all times and taking into account technical constraints for all the considered technologies (e.g. ramping rates, minimum stable generation levels, etc.).

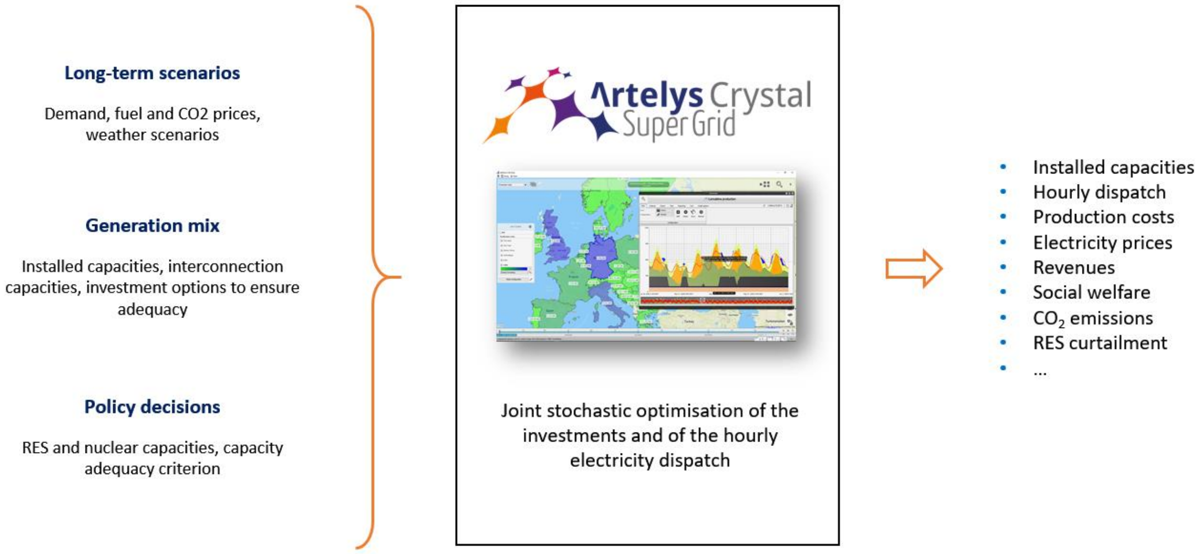


Figure 7. Schematic description of Artelys Crystal Super Grid

When one ranks the available power plants based on ascending short-term marginal cost of production, one defines the so-called **merit order**. For a given weather scenario, Artelys Crystal Super Grid dispatches the production in Europe for each hour of the year (8760 consecutive time-steps per year) according to the merit order. The exchanges between countries are constrained by the available net transfer capacities (see assumptions below).

A typical merit order is depicted in the following figure:

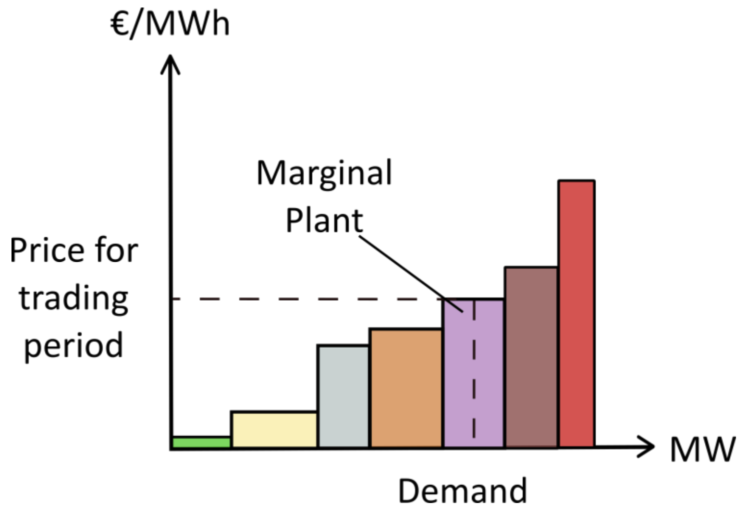


Figure 8. Illustration of the merit order and clearing in a perfect market.

The previous figure displays the power demand at a given time step, represented by a dashed vertical line, and the different production types, represented by blocs whose height correspond to their variable cost (in €/MWh) and width correspond to their installed capacity (in MW). The production units are sorted in order of increasing variable costs, from the cheapest one to the most expensive one. In a purely economic approach, the cheapest capacities are turned on first, until generation reaches the demand. The last called capacity is the marginal unit and defines the marginal cost or shadow price of electricity for this time-step (an hourly time resolution is use throughout this study).

The following graph shows how the expected 2030 Swiss production (using the assumptions of the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario) is dispatched between the different production units and imports/exports, so as to meet the Swiss power demand. Each coloured area represents a given technology, while the solid red line represents the Swiss hourly demand.

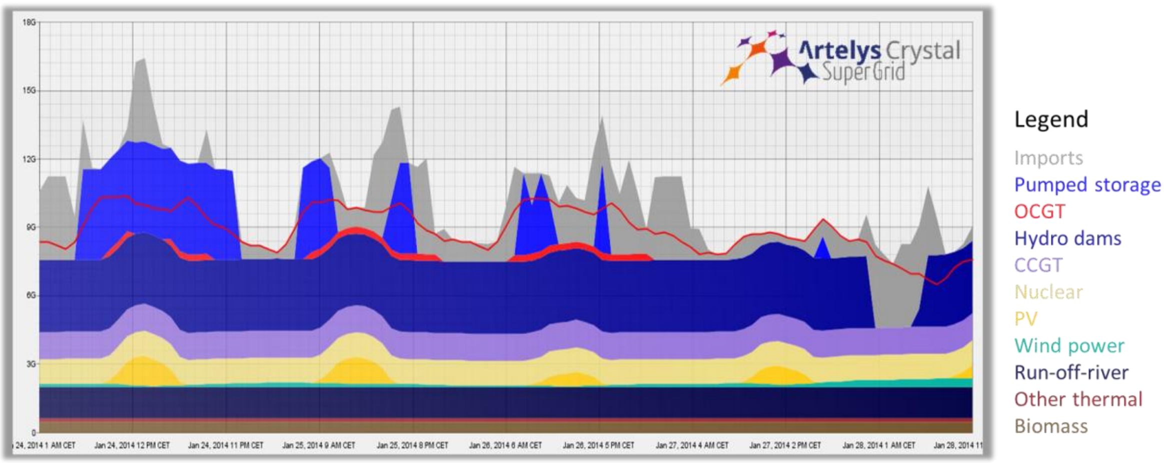


Figure 9. Cumulative generation curve for Switzerland during 4 typical days in winter 2030, as simulated by Artelys Crystal Super Grid

From bottom to top of Figure 9, we can identify biomass generation (brown), hydro run-of-the-river (darkest blue), nuclear (light yellow) and CCGTs generation (purple) which are found to have a constant baseload generation profile over the considered period. The daily and weekly flexibility is mainly provided by large hydropower dams (medium blue), pumped hydro storage units (light blue) and OCGTs (red). Imports (grey) provide the difference between local supply and demand. Solar generation is shown in yellow, while wind power is shown in green. Finally, the grey area shows the imports/exports via interconnectors.

When the sum of the coloured areas (production and imports) exceed the demand, the surplus is exported to neighbouring countries. It is worth noting that, as in real life, the model allows a country to simultaneously import electricity from a country and export electricity to another country if it is economically interesting.

For this study, we have adopted **country-level spatial granularity** meaning that the national transmission and distribution networks are not taken into account, although demand assumptions include network losses. In addition, units of each type or technology - e.g. nuclear, wind power, hydro assets - are aggregated in each country into a unique asset called "fleet"

Switzerland and its neighbouring countries (France, Germany, Italy and Austria) are modelled explicitly, while the other ENTSO-E countries have been aggregated into 6 zones (Benelux, Iberian Peninsula, British Isles, Scandinavia, South-Eastern Europe and Eastern Europe) in order to reduce computation time[5].

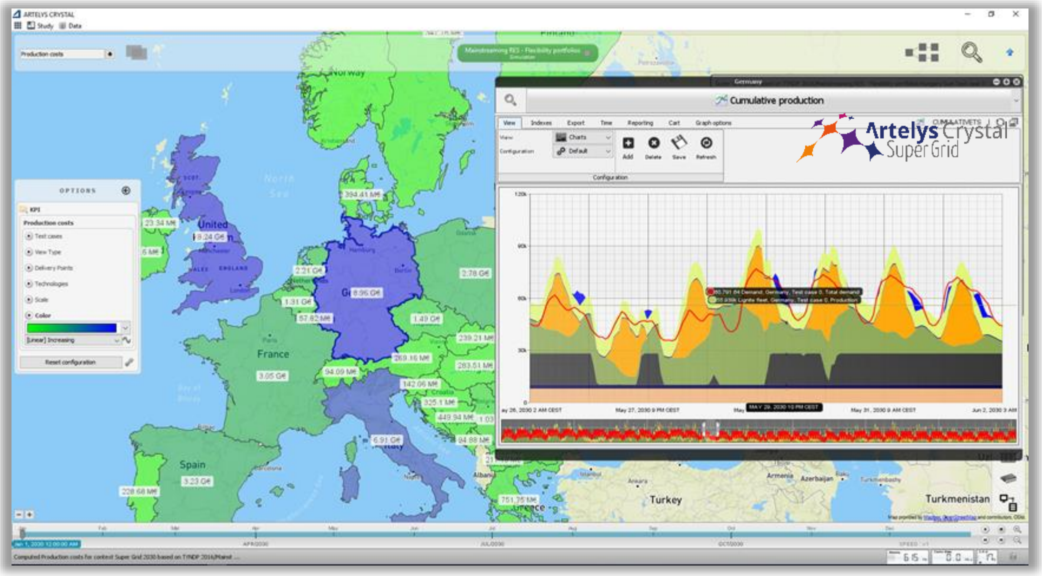


Figure 10. The European power system in Artelys Crystal Super Grid.

The simulations performed **jointly optimise the dispatch in every zone** of the model while taking into account interconnection capacities between zones.

In order to accurately describe the possible dispersion of revenues for RES producers due to the variability of weather conditions from one year to the next, we have used 50 different annual weather scenarios (see Section 2.b for more details). Each weather scenario has been simulated with an hourly time resolution. For each scenario, we have determined the time-series of marginal production costs (the shadow variable of the hourly demand-supply constraint), which is interpreted as the wholesale electricity price that drives the RES producers' revenues.

The time resolution adopted during this study (8760 consecutive time-steps) allows to take precisely into account RES generation and demand variability, leading to a more robust estimate of RES revenues and impacts of RES on storage management than models

[5] In practice, this means that we assume infinite interconnection capacities and perfect coupling between countries in the same zone. The impacts of this simplification are found to be negligible when compared to the effects of the phenomena we investigate in this study.

belonging to the MARKAL/TIMES family of models (such as the Swiss TIMES model[6] developed by PSI) which are based on typical days/hours. An explicit description of the transmission grid, as adopted by the SwissMod model[7], could be a useful addition to the model, especially if one aims at optimising the localisation of RES investments and network reinforcements, which was outside the scope of this study.

ii. Modelled assets

Artelys Crystal Super Grid allows to model the demand, generation assets, interconnectors, storage assets, etc., while taking into account technical constraints for each of the fleets. The model used during this study relies on previous work performed for the European Commission in the context of the METIS project [10]. The most important assumptions for each asset are described below. The corresponding techno-economic parameters are given in Section 2.a.iii.

Electricity demand

The power consumption is represented with an hourly time resolution. The annual consumption of Switzerland is based on the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario (more details in section 2.a.iii and 2.b) while it is based on the ENTSO-E vision 1 and 3 for the other countries and zones. The hourly demand profiles are based on the publicly available ENTSO-E TYNDP datasets. The influence of the temperature on the demand (due to the share of heat pumps and electric heating in winter and air conditioning in summer) is captured through a load-sensitivity analysis. The demand profiles are also correlated with renewables generation curves (see section 2.b for more details).

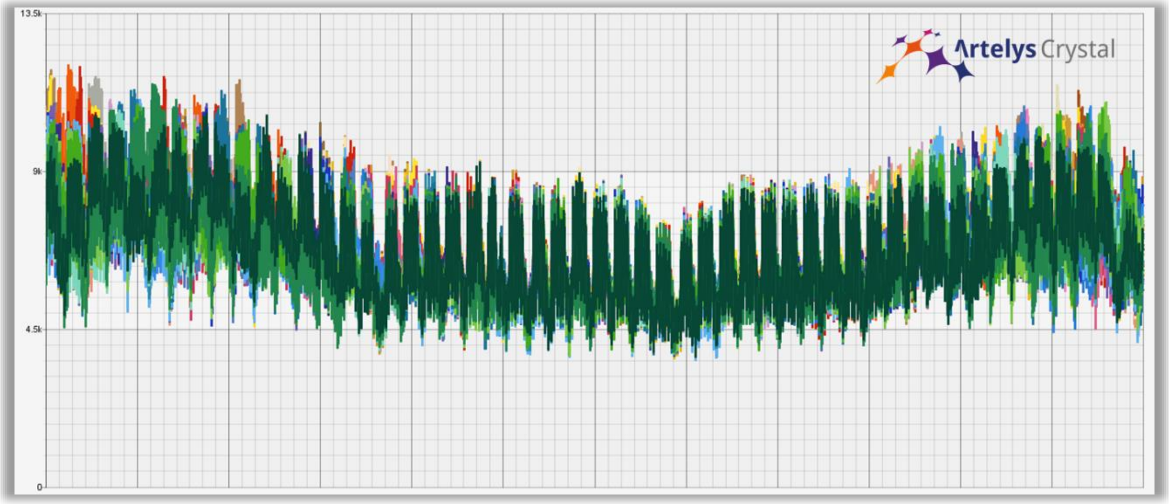


Figure 11. Fifty years of projected consumption hourly time series for Switzerland in 2030

In Figure 11, we display the 50 scenarios of hourly consumption in Switzerland in 2030 that are considered in the study. One can note that the consumption profile varies more in winter (right and left part of the curve) than in summer (centre part of the curve) due to the temperature-dependent consumption of electric heating.

Thermal generation

Thermal generation is represented by an asset per fuel type (e.g. nuclear, coal, lignite, oil, etc.), and two assets for gas-based generation (OCGT and CCGT) in each country. The generation of each of these assets is optimized for each hour of the year. Their installed capacities are based on exogenous scenarios (e.g. *Neue Energiepolitik C&E*

[6] https://www.psi.ch/eem/PublicationsTabelle/2014-STEM-PSI-Bericht-14-06.pdf
[7] https://wwz.unibas.ch/uploads/tx_x4epublication/Swissmod_Schlecht_Weigt_2014.04.pdf

Sensitivitätsanalyse Photovoltaik 1 for Switzerland and ENTSO-E for the other modelled countries and zones), while the availability is based on TSO historic data. The generation costs depend on the fuel prices, the efficiency of the considered technology, as well as on the CO_2 price.

Variable renewable generation

In each country, variable renewable generation is represented by an asset per type of technology, including onshore and offshore wind, solar PV, hydro run-of-the-river, and other variable renewables. The generation of each of these assets is computed as the product of their installed capacities (in MW) and on their load factor profiles (time series between 0 and 1), which are based on historical generation datasets. In the following figure, we present 10 curves of hourly load factor for wind generation that are considered in the study for Switzerland in 2030. These curves take values between 0 and 1, and are based on measured wind data from 2001 to 2010. The generation of these curves is described in the appendix (see paragraph b.i for more details).

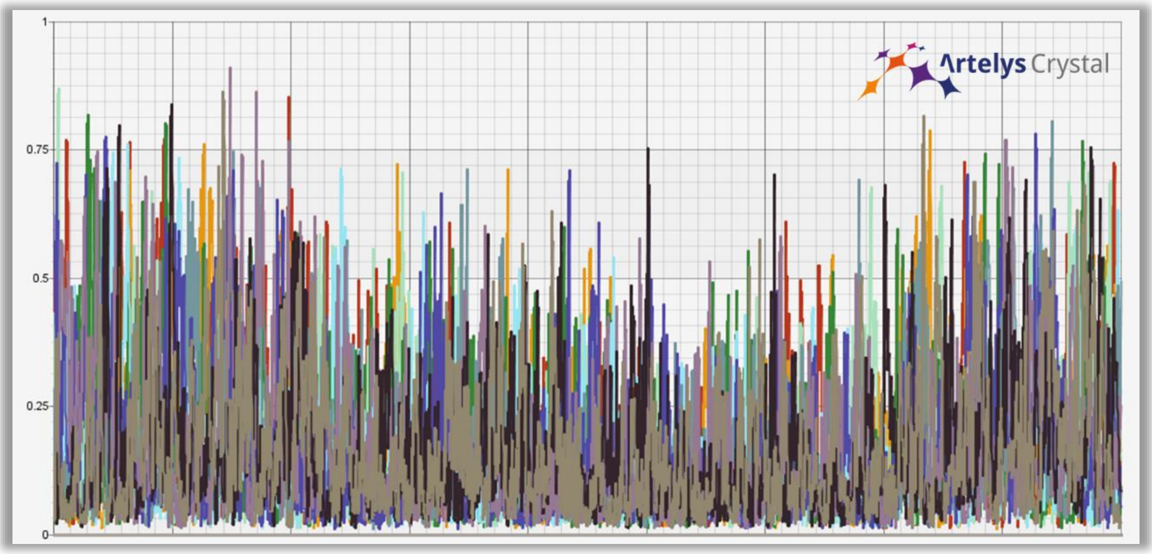


Figure 12. Ten years of wind generation load factors hourly time series for Switzerland in 2030.

Hydro storage

Two categories of hydro storage technologies are represented in the model: large hydro reservoirs and pumped hydro storage.

Large hydro reservoirs are characterised by an important storage capacity and a seasonal management. In the model, they are represented by a single asset aggregating them at a national level, and whose parameters are an installed power generation capacity, a storage capacity and a water inflow curve built using the national water inflow figures from the SFOE (see [11-14])[8]. The generation of this asset is optimised by the model. While the model does not take into account variable costs or a pre-calculated water value, its management follows a logic of guide curve, meaning that its storage has to be higher than a given value at the end of each week. In this sense, the model makes sure that the storage is high enough so that the system has enough flexibility to face most situations.

[8] As such, the objective of this asset is to reproduce the overall behaviour of the sum of the generation of all hydro reservoirs and not the individual management of each one.

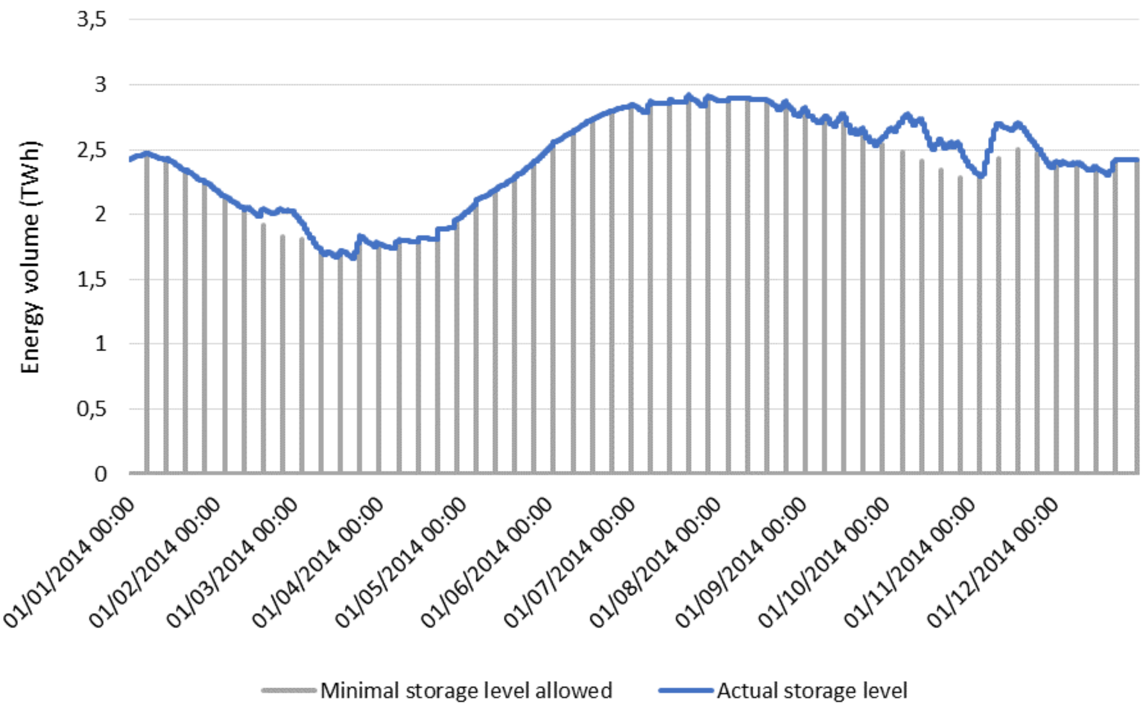


Figure 13. Illustrative inter-seasonal storage management replicated (France in standard climate conditions) (source: METIS [10])

Pumped hydro storage (PHS) assets are characterized by smaller storage capacities and are usually managed with daily or weekly cycles. In the model, PHS units are aggregated at national level and characterised by an installed capacity, a storage capacity and roundtrip efficiency. At each hour, a pumped hydro storage asset can either produce electricity by releasing water from the reservoir, or consume electricity to pump water back into the reservoir, as decided by the optimisation model. While PHS units are taken into account in the modelling, their revenues and related risks have not been assessed in this project. Indeed, when studying storage technologies, it is essential to use highly-detailed models that take the precise structure of the generation portfolio into account so as to represent all the arbitrage opportunities that PHS units can exploit. Artelys Crystal Super Grid includes models that can take into account start-up costs, running or "no-load" costs, ramping costs, etc. Publicly available datasets that can be used to configure such models have been released by third parties towards the end of the project and have not been used during this study[9].

More details are given on the hydro generation in Switzerland in section 2.b.

Interconnectors

Electricity can be exchanged from one zone to the other using interconnectors (high voltage transport lines). Each interconnector is considered as being able to exchange electricity in both directions (although the capacity in each direction might differ, due to local congestion issues). The direction and intensity of the flows on the interconnectors can change from one hour to the next. The joint optimisation of flows on interconnectors and the production dispatch represents the dynamics of a coupled European power grid. The exchange capacities are based on NTC values given in Section 2.a.iii.

[9] See for example the OSeMBE database - http://www.osemosys.org/osembe.html

iii. The Swiss power system in 2030

The scenario describing the 2030 power system of Switzerland used in our study is the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* of the Swiss Federal Office of Energy.

The Swiss Energy Strategy 2050, the first package of which has been approved by the Swiss people on 21 May 2017 via referendum[10], has been developed by the Swiss Federal Council to prepare Switzerland for the upcoming challenges related to the fundamental changes in the energy markets that are driven by economic and technological developments and policy decisions all across Europe.

The Energy Strategy 2050 defines new energy and climate policies that ensure that Switzerland benefits from a secure and cost-efficient supply of energy, while reaching ambitious CO_2 reduction targets. Furthermore, the strategy strives at reducing the Swiss energy-related impacts on both the climate and the environment[11].

The strategy is based on three pillars:

1. **Increasing energy efficiency** – Policy measures are implemented in all sectors (buildings, mobility, industry, and appliances) to reduce the use of energy. The Energy Act[12], which contains policy measures that will be active over the 2018-2035 period, targets a 43% reduction of the per capita use of energy by 2035 compared to 2000. In the electricity sector, a 13% reduction per capita is targeted due to the impact of electrification of the mobility and heating sectors (heat pumps).
2. **Increasing the use of renewable energy** – Policy measures are implemented to promote renewable energy and to improve the current legal framework. The Energy Act adopts a 2035 target of 11.4 TWh of renewable electricity (excl. hydropower). Hydropower is also expected to increase its production to reach 37.4 TWh by 2035. The mechanisms used to support the deployment of renewables, which are at the core of this study, aim at replacing the current feed-in remuneration at cost scheme by a feed-in remuneration with direct marketing, with potential exemptions for small facilities. A number of support measures have already been approved, in particular for hydropower (for new investments, as well as for existing assets that cannot recover their fixed costs due to the current low level of electricity prices). These measures are financed through the 2.3 cts/kWh tax on electricity consumption[13].
3. **Withdrawal from nuclear energy** – No new general licences for nuclear power plants will be granted. The existing nuclear power plants can continue their operations as long as their safety is guaranteed.

A combination of policy measures have been proposed in the so-called "first package of measures" to meet the objectives of the Swiss Energy Strategy 2050. This first package is expected to enter into force on January 1st 2018 as a reform of the Energy Law and its associated ordinances.

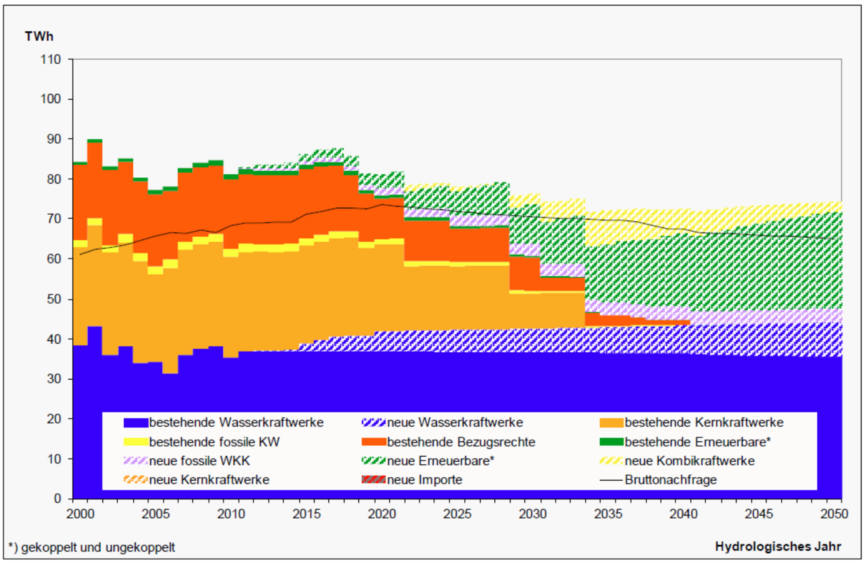
Should the Energy Strategy 2050 be successfully implemented, then the energy generation mix by 2030 could look like the one depicted by Figure 14, which shows the expected evolution

[10] https://www.admin.ch/ch/d/pore/va/20170521/det612.html
[11] The Swiss National Council and the Council of States have recently approved the Paris Agreement, see https://www.parlament.ch/de/ratsbetrieb/suche-curia-vista/geschaeft?AffairId=20160083
[12] https://www.admin.ch/opc/de/federal-gazette/2016/7683.pdf
[13] http://www.bfe.admin.ch/energiestrategie2050/index.html?lang=en&dossier_id=06702

of the generation by technology in the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario[14].

In particular, the electricity demand is expected to peak in 2020, mainly as a result of the projected slowdown of the population increase and strong energy efficiency efforts. Nuclear reactors will be decommissioned progressively and are expected to be completely phased-out by 2034 at the latest, while long-term import contracts expire in 2040[15]. Investments in new generation technologies (small hydropower, solar PV, wind power, CHPs and gas-fired units) are assumed to progressively replace these sources of electricity. Gas-fired units are only expected to be operated during a transition period (roughly 2025 to 2040), as the phase out of nuclear capacity might occur at a faster pace than the deployment renewable generation technologies.

Figur 3-4: Sensitivität 1, Szenario „Neue Energiepolitik", Perspektiven der Elektrizitätsversorgung, hydrologisches Jahr, in TWh_{el}/a



Quelle: Prognos 2013

Figure 14. Electricity generation and gross consumption from 2000 to 2050 in the scenario Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1 (source SFOE, [7])

The main assumptions about the Swiss energy mix in 2030 adopted in our model are presented below. Some of the assumptions are directly extracted from the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario, while others are based on other sources, which are presented below, notably for hydro and RES generation (see [11-14]).

Electricity demand

The Swiss 2030 electricity demand (excluding the consumption of PHS units) is assumed to slightly decrease compared to its 2020 value, as can be read from Figure 14.

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14 http://www.bfe.admin.ch/themen/00526/00527/06431/index.html?lang=de&dossier_id=06421

15 Some of these contracts have already been abandoned by Swiss utilities – see e.g. https://www.letemps.ch/economie/2017/09/12/alpiq-axpo-bkw-ne-sapprovisionneront-plus-fessenheim

	2030
Demand	60.72 TWh

Table 1. Annual 2030 electricity demand in the Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1 scenario

Wind and solar PV generation

Wind and solar PV generation are assumed to increase considerably compared to 2015[16]:

- Solar PV: increase of the annual generation by around 3000 GWh
- Wind power: increase of the annual generation by around 1300 GWh

	Installed capacity	Expected generation
Solar PV	4562 MW	4034 GWh
Wind	1017 MW	1460 GWh

Table 2. 2030 wind and solar PV installed capacities and expected generation in Switzerland

The average number of full-load hours (FLH) are assumed to be 884 hours for solar PV and 1436 hours for wind power. The generation profiles of both technologies are discussed in section 2.b.

Hydroelectric installed capacities

The 2030 Swiss power system will still strongly rely on hydropower, with some new capacity installed allowing the average hydro generation to amount around 42 TWh (excl. PHS). PHS units are assumed not to receive natural water inflows in the model, and to have an overall efficiency of around 80%.

	Power capacity	Storage capacity	Expected generation in 2030
Run of river	4 188 MW	-	21 963 GWh
Hydro reservoir	8 141 MW	8 800 GWh	19 710 GWh[17]
PHS	3 979 MW	674 GWh	Optimised by the model

Table 3. Hydroelectric generation in Switzerland, in 2030

While the management of PHS units is optimised by Artelys Crystal Super Grid, it has been decided not to assess their revenues and risks in this study.

Other generation capacities

While the Swiss energy mix is assumed to be mostly renewable by 2030, some thermal generation units remain in the mix. In particular, it is assumed that nuclear capacity will decrease by around 60% compared to the current 20-25 TWh of annual nuclear generation (see [11]).

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[16] Based on Table 3-8 of [7]. Capacity figures are obtained via a weighted interpolation between 2027 and 2032. 2015 values are based on [11].

[17] The annual production is assumed to be 19 710 GWh in average over the climatic scenarios, but the hourly dispatch is optimised by the model. More details are provided in section 2.b.i.

	Installed capacity	Expected generation
Nuclear	1 535 MW	8 810 GWh

Table 4. Nuclear generation in Switzerland, in 2030

Conventional gas-based thermal technologies are assumed to have a capacity of 1 800 MW in 2030.

	Installed capacity (MW)
CCGT[18]	1500
OCGT	300

Table 5. Gas-based generation in Switzerland, in 2030

Finally, other generation types are also present in the mix, such waste incineration plants (waste being considered at 50% renewable) and biomass CHP units. They are considered as must-run (base load) units in our model.

	Installed capacity (MW)
Must-run non-renewable	199
Must-run renewable	509

Table 6. Must-run generation in Switzerland, in 2030

Interconnectors

The capacity of the interconnectors between Switzerland and its neighbours is based on the ENTSO-E TYNDP 2014 datasets [17].

Interconnection	Installed capacity (MW)
Switzerland → Austria	2200
Austria → Switzerland	2500
Switzerland → France	2800
France → Switzerland[19]	4200
Switzerland → Germany	5000
Germany → Switzerland	5000

[18] The repartition between CCGT and OCGT is assumed to remain identical to the one prevailing today (i.e. 1/6 OCGT, 5/6 CCGT).
[19] The 2014 version of the ENTSO-E TYNDP includes 4 so-called "Visions" of the 2030 European power system. Most of the interconnection capacities remain constant over all the visions. However the FR-CH interconnection capacity is 4200 MW in Vision 1, and 4700 MW in all other visions.

Interconnection	Installed capacity (MW)
Switzerland → Italy	5900
Italy → Switzerland	3650

Table 7. Interconnection of Switzerland to its neighbour countries, in 2030 for both import and export.

RES capacities in the considered scenario

For future reference, we provide in the following table the RES capacities for different time horizons (2017, 2030 and 2050) taken from the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario (Swiss Energy Strategy 2050). These values have been obtained based on figures of annual energy generation by technology, assuming that the load factor remains constant.

Projected capacities (MW)	Solar PV	Wind	Run-of-the-river	Hydro reservoir
2017	1679	372	3889	8108
2030	4562	1017	4188	8141
2050	12575	2967	4464	-

Table 8. 2017, 2030 and 2050 RES installed capacities

The 2050 figures will serve as maximum potential assumptions in Section 4 when we illustrate the impact of a technology-neutral support scheme in which solar PV, wind and run-of-the-river technologies are eligible to participate.

b. Modelling short- and long-term uncertainties

This project focuses on the risks impacting market revenues that can be expected by RES producers in 2030, and on the impact of these risks on the investments by RES producers. For that purpose, we have studied the factors that can influence the market revenues, which are presented in the following paragraphs.

Two categories of uncertainties that have a significant effect on electricity prices, and following on market revenues for generation units, are taken into account in our simulations:

- **Infra-annual uncertainties** – This first category of uncertainties corresponds to weather variability (temperature, solar irradiation, wind speeds and precipitation), which impacts the demand (via a load-temperature gradient), RES generation, and water inflows in hydro reservoirs. These variations have a sizable impact on the dispatch of power plants and hence on electricity prices. The construction of the different weather scenarios partly rely on previous work undertaken in the context of the project METIS for the European Commission (see [10]). 50 weather scenarios covering the whole of Europe are considered in this study.
- **Long-term uncertainties** – This second category of uncertainties corresponds to the long-term uncertainty related to the evolution of the European energy system and of fuel and CO_2 prices. These uncertainties are taken into account by considering two 2030 scenarios for the rest of Europe: the “Slow Progress” (also called Vision 1 or V1) and “Green Transition” (also called Vision 3 or V3) from the ENTSO-E’s TYNDP 2014 [17]. These scenarios impact many aspects of the electricity sector: national generation

mixes, fuel and CO_2 prices, interconnection capacities and annual demands (in particular due to energy efficiency assumptions).

More details on each category of uncertainties are provided in the next two sections.

i. Infra-annual uncertainties

In order to properly capture the uncertainty on RES generation and electricity prices related to weather scenarios, the model takes into account the variability of demand, RES generation and water inflows, depending on the weather scenario. In particular, 50 realisations of weather variations were built, combining demand time-series, RES generation and water inflows in a way that conserve the observed correlations between these factors.

The general approach is given below. An appendix giving more details on the methodology developed in the context of the METIS project is also available in section 6.

Consumption

In the METIS project, 50 consistent hourly time series of consumption have been built for each ENTSO-E country, for the ENTSO-E Vision 1 and Vision 3 scenarios. In more details, for each scenario long-term scenario, 50 demand time-series have been built by:

1. **Step 1** – Analysing the load-temperature sensitivity (i.e. determining by how many MW does the demand increase when the temperature drops by 1°C below a heating threshold, or by how many MW is increases when the temperature increases by 1°C above an air-conditioning threshold)
2. **Step 2** – Using the results to project the demand over 50 years (1965 – 2014) of measured temperatures at the country level.

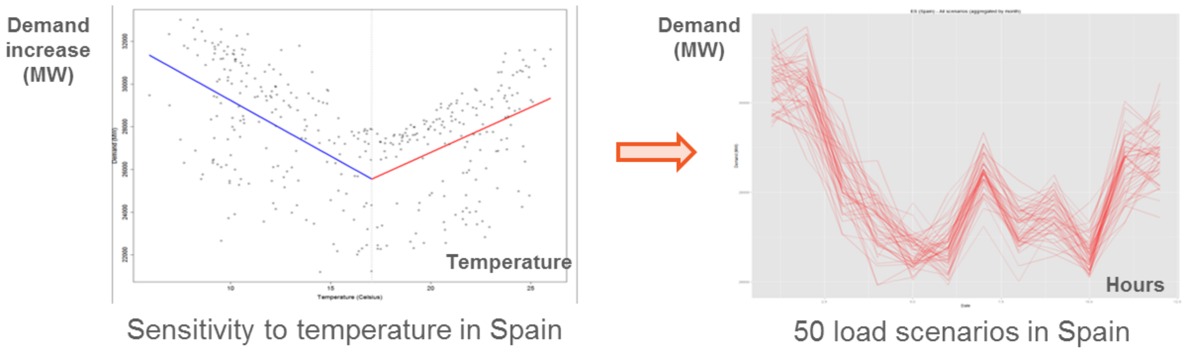


Figure 15. Two gradients and one threshold accounting for heating and cooling effects on Spain demand (source: METIS [10])

The process described in Figure 15 shows on the left the consumption dependency on temperature for Spain (Step 1). As expected, consumption increases when the weather is cold (due to heating) or very warm (due to air conditioning). The RHS figure presents the resulting 50 years of hourly time-series of consumption for Spain (Step 2).

For Switzerland, an additional step is taken to build the consumption time-series. Indeed, since the annual electricity consumptions that is assumed in this study (based on *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1*) differs from the Swiss annual consumption figures of the scenarios V1 or V3 from the ENTSO-E, the Swiss consumption time-series of the V1 scenario is re-scaled so that the average annual consumption (over the 50 weather scenarios) corresponds to the 2030 consumption level we have adopted (see Section 2.a.iii.) Consequently, the demand exceeds the *Neue Energiepolitik* scenario figure for some weather scenarios while it is below this figure for the others.

RES generation profiles

Wind and solar PV load factor time series have also been built during the METIS project, based on 10 years (2001-2010) of historic data of wind and solar irradiation at the country level, and on transfer functions from wind and irradiation to power generation. This methodology, implemented with the help of the Institute of Power Systems and Power Economics (IAEW) from RWTH Aachen University, is described in more details in section 6.

For Switzerland, as for consumption, the Swiss load factor time-series obtained using this process are then multiplied by a coefficient so that the average load factor corresponds to the assumption used in the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario. As a consequence, the wind (or solar PV) generation exceeds the *Neue Energiepolitik* figure for some weather scenarios while it is below for some other scenarios.

The 10 RES generation time-series obtained are combined with the temperature data so that the consumption and RES data are consistent over the 2001-2010 period. For the years outside the 2001-2010 range, the 10 generation time-series are combined with demand time-series so that the temperature year 19YX is matched with RES generation year 200X.

Hydro generation in Switzerland

A considerable attention has been paid to hydro generation in Switzerland, and its dependence on weather conditions. Indeed, datasets published by the SFOE and the Swiss Federal Office of Statistics (see [11] to [14]) show that hydro reservoir generation can vary in the range between 16 and 24 TWh per annum, meaning that the generation can considerably vary from one year to the next. This is in particular due to the variation in water natural inflows[20] and storage levels at the end of the year, which can vary depending on the expectation of a cold or warm winter.

For that purpose, 10 weather scenarios were built based on historic SFOE data (2001-2010). In particular, the following datasets have been used in our model:

- Load factor for run-of-the-river hydroelectricity based on data from SFOE Weekly Electricity Statistics [12]. Its generation is assumed to remain constant at the weekly level.

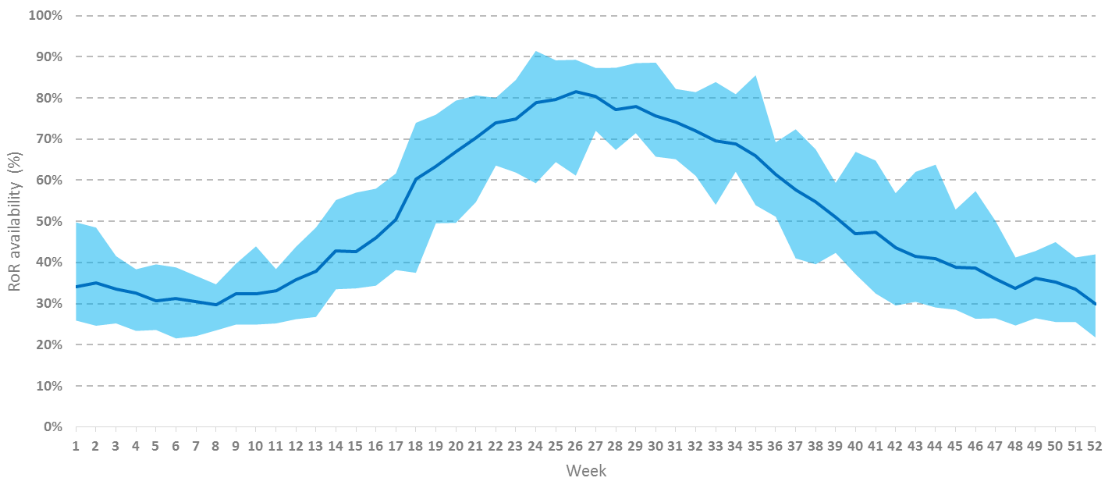


Figure 16. Load factor of run-of-the-river in Switzerland based on historic data. (minimum, maximum, and average of weekly generation over the period from 2001 to 2010)

[20] Excluding derivation and pumping.

- Water natural inflows for large hydro reservoirs. These are computed at a monthly granularity, based on the storage level at the end of each month and on the monthly generation, based on data from SFOE Electricity Statistics [11-14].

In addition, a guide curve has been built based on the storage level at the end of each month for 2001-2010. This guide curve remains identical for each weather scenario and defines a minimum storage level that the operator has to keep in the reservoirs at the end of each week. The value taken for each week is the second highest value of the 10 historic storage level curves from 2001 to 2010. This allows to be conservative while avoiding extreme years, as we can see in Figure 17, where the 10 historic curves are presented along with the chosen guide curve in red.

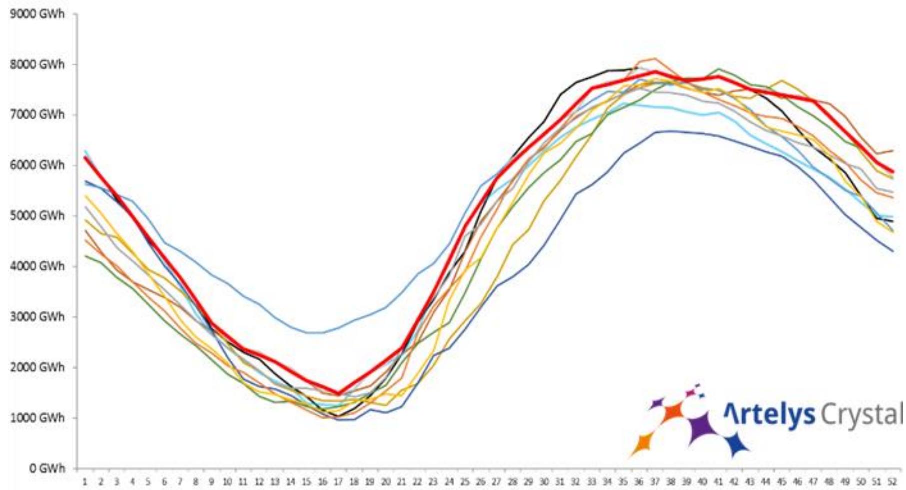


Figure 17. Hydro reservoir storage level for ten years of data. (data source: SFOE)

The hydro weather scenarios are then combined with the RES generation and demand scenarios so as to obtain consistent scenarios over the 2001-2010 period.

Note that while the variations of generation from 2000-2010 are taken into account in this work, thus taking into account dry and wet years, the long-term uncertainty on hydro-power generation related to climate change has not been taken into account.

ii. Long-term uncertainty

In the study, the long-term uncertainties related to the European generation mixes, fuel and CO_2 prices, interconnection capacities and electricity consumption are captured by taking into account two long-term scenarios from the ENTSO-E TYNDP 2014 (see [17]) : **Vision 1** (also called "Slow Progress") and **Vision 3** (also called "Green Transition"). These scenarios are possible and contrasting futures for the energy context outside of Switzerland in 2030 corresponding to different economic and political contexts, as described by the next figure.

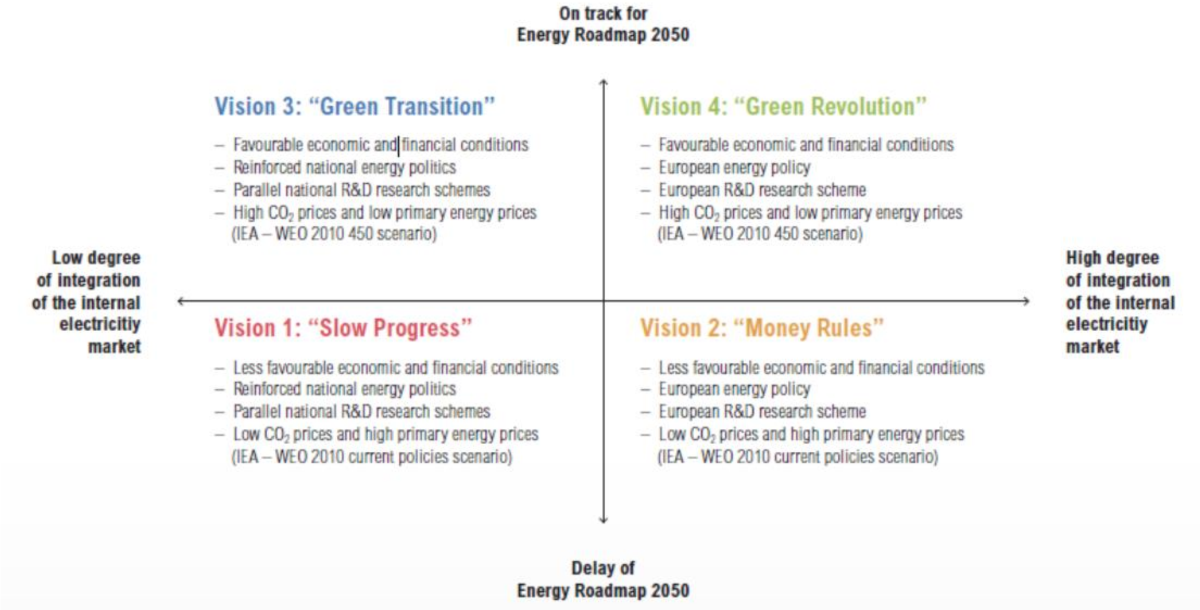


Figure 18. Overview of the political and economic frameworks of the four Visions (source: ENTSO-E TYNDP 2014)

The difference of economic and political frameworks between the two visions (particularly for CO_2 and fuel prices) translates into very different power demands and capacity mixes in Europe in 2030, as described in Figure 19.

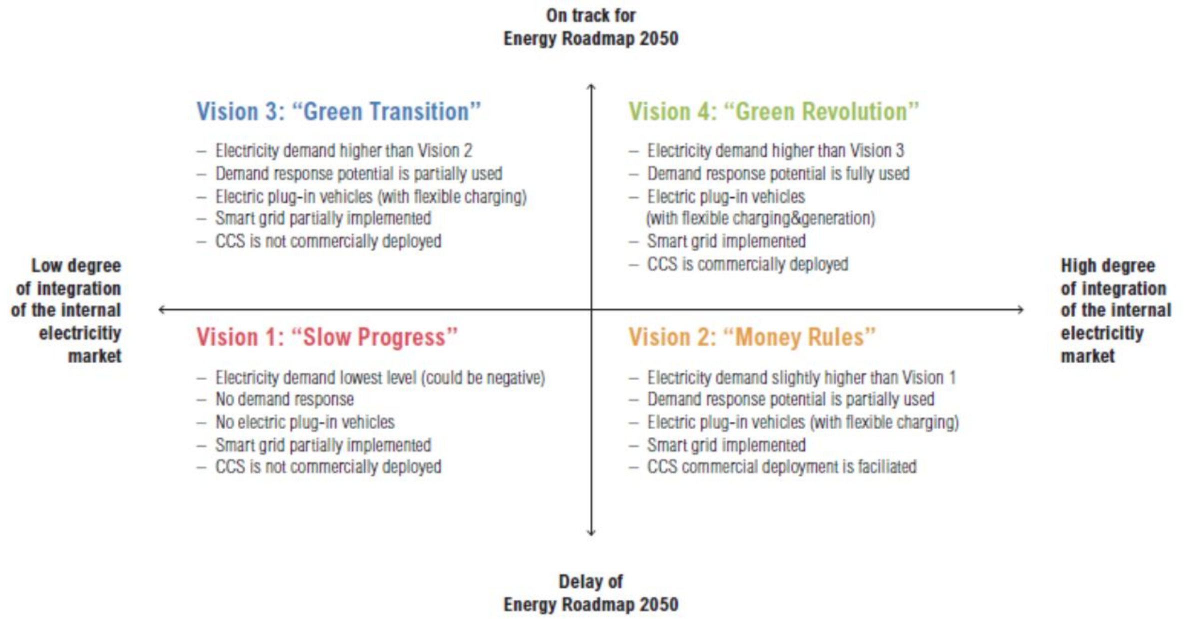


Figure 19. Overview of the generation and load frameworks of the four Visions (source: ENTSO-E TYNDP 2014)

In particular, Vision 3 is characterised by a higher power demand than Vision 1 due to a better economic context and to the electrification of some end-uses such as mobility. The difference amount to around 15% in terms of annual European power demand.

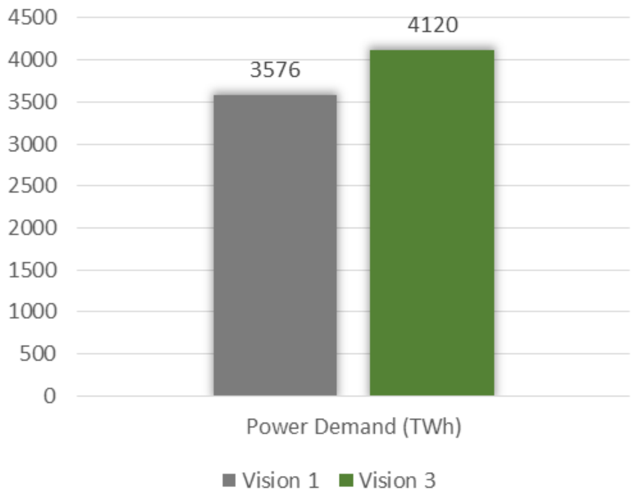


Figure 20. Annual power demand in ENTSO-E countries. The Swiss demand from the Neue Energiepolitik scenario is adopted instead of the ENTSO-E figure (sources: TYNDP 2014 and SFOE)

The higher power demand in Vision 3 is partly met thanks to higher RES capacities throughout Europe, especially for wind and solar generation, as depicted below.

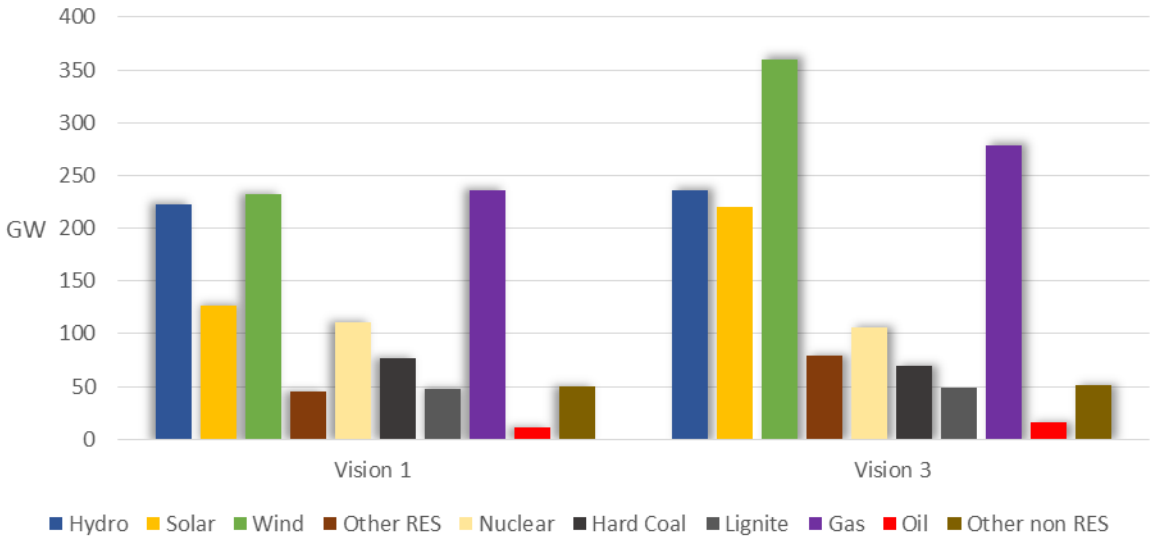


Figure 21. Installed capacities throughout ENTSO-E countries, without Switzerland (source: ENTSO-E TYNDP 2014)

One could argue that the spirit of the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* is close to the one of V1 in terms of the Swiss electricity demand, but similar to the one of V3 in terms of RES ambition. In order to conduct a proper analysis of the compatibility of the storylines of the ENTSO-E scenarios with the *C&E Sensitivitätsanalyse Photovoltaik 1* considered herein, one should analyse the assumptions of the latter scenario for Europe.

Although wind and solar PV capacities are significantly higher in the Vision 3 scenario, which could lead to a decrease in investment and O&M costs for these technologies through innovation and scaling effects, we assume in the following that the technology costs remain identical for the two long-term scenarios. As such, the risks related to the variation of technology costs on the generators' financial balance are not taken into account.

Still, to cover that aspect, an analysis of the sensitivity of the RES support levels to the level of fixed costs (annual CAPEX and OPEX) has been performed and is presented in Section 4.c.ii.

In addition to the composition of the generation mixes and demand levels, the two selected ENTSO-E TYNDP scenarios assume different fuel and CO_2 prices, which are used for Switzerland and the other countries (meaning that the merit order between fleet is the same across Europe), and which are shown in the next table.

	Vision 1	Vision 3
Gas price	37.0 €/MWh	28.5 €/MWh
Coal price	12.5 €/MWh	8.0 €/MWh
Oil price	83.5 €/MWh	60.2 €/MWh
CO_2 price	31 €/tonne	93 €/tonne
Nuclear generation cost	4.18 €/MWh$_e$	4.18 €/MWh$_e$

Table 9. 2030 Fuel and CO_2 prices used in the study, in €$_{2013}$.

In particular, one should note that the high CO_2 price that is assumed in Vision 3 has an impact on the merit order, as it reverses the order between coal/lignite units and gas units. In Vision 1, coal and lignite units are found to have lower variable generation costs than CCGTs, while in Vision 3, CCGTs become cheaper than coal and lignite units, as illustrated below.

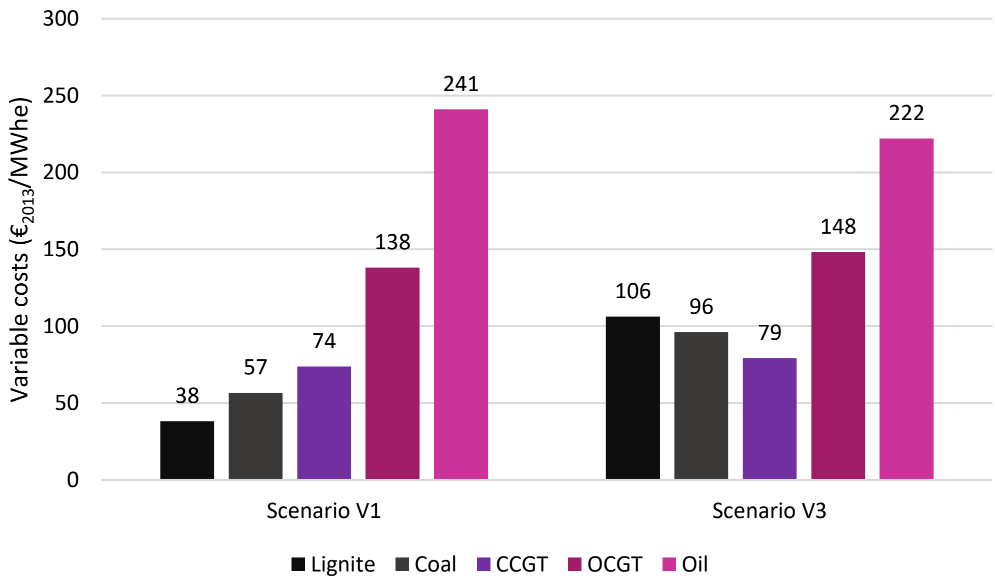


Figure 22. Variable generation costs of lignite, coal, gas and oil fleets in Switzerland and Europe in 2030, for the two long-term scenarios, in €$_{2013}$.

As a consequence, the load factors of these technologies can exhibit substantial variations between Vision 1 and Vision 3.

The CO_2 emission factors used in the study are presented in the following table:

	CO_2 emission factors per unit of fuel
Gas	0.19 t/MWh
Coal	0.33 t/MWh
Lignite	0.43 t/MWh
Oil	0.26 t/MWh

Table 10. CO_2 emission factors used in the study (lower heating value).

Note on system adequacy

The level of adequacy between the installed capacities and the demand can have a significant impact on electricity prices and, through these, on market participants' revenues. However, on the medium to long-term, one is likely to see the current level of overcapacity to be resorbed, as it depresses prices and negatively impacts market revenues.

Therefore, in the context of this study, we assume that the European generation mixes are well adapted to the demand levels. To reflect this in our modelling, we optimise the capacities of the gas-fired[21] units in all European countries but Switzerland (for which we use the figures presented above).

This optimisation is performed using the capacity expansion planning capabilities of Artelys Crystal Super Grid: the CCGT and OCGT installed capacities and the hourly dispatch of all generation fleets are jointly optimised on 50 annual weather scenarios, for both long-term scenarios (Vision 1 and Vision 3). The installed capacities of all the other technologies (e.g. nuclear, coal, lignite, hydro, RES, etc.) are given by the ENTSO-E TYNDP values.

The optimisation thus finds the optimal trade-off between installing additional gas capacities and not being able to supply the entire demand. The OCGT and CCGT costs are given in the next section, while a value of loss of load of 15 000 €/MWh has been adopted during the capacity expansion phase (leading to an average 3-4h of loss of load per year).

All the simulations presented in the next sections are performed using the two set of capacities obtains through the capacity expansion exercise (one for the long-term scenario V1 and one for scenario V3), each combined with the 50 weather scenarios that represent the intra-annual variability of climatic conditions. In these simulations, the cap on the price of electricity is set to 3 000 €/MWh to represent the typical current value of price caps in day-ahead markets. If higher price caps were to be adopted, as is being proposed by the European Commission in the "Clean Energy for All Europeans", market revenues would be likely to increase, in particular for peaking plants such as OCGTs and PHS which would be able to more easily recover their fixed costs. Exploring the impacts of higher price caps (and of other policies and measures proposed by the European Commission) on the revenues of the different technologies of the future Swiss power sector could be a direction for future research.

[21] This optimisation is performed only for gas fleets as their capacity is mostly driven by the revenues they can get on the markets. As such their capacity tends to be optimised, which is not the case for most other generation types such as RES, nuclear or coal capacities, whose deployment or phase-out are often led by policy decisions.

c. Assumptions on technology costs

The following tables present the technology costs used in this study. They rely on the *Energy Technology Reference Indicator for 2010-2050 from the Joint Research Centre of the European Commission* [18], whose figures are presented in the Table 11[22]. These values correspond to 2030 projections of investment and O&M costs for OCGT, CCGT, and RES technologies in Europe, i.e. the costs for new investments in 2030. As such, they do not correspond to Switzerland-specific assumptions which might be higher (e.g. because of location, wages, regulation, etc.). However, to cover the possible range of investment cost, a sensitivity analysis has been performed. The results are presented in Sections 4 and 5.

Technology	CAPEX ($k€_{2013}$/MW)	Annual fixed O&M costs (% of CAPEX, per year)	Lifetime (y)
OCGT	550	3,0%	30
CCGT	850	2,5%	30
Large hydro	3 370	1,5%	60
Run of the river	5 620	1,5%	60
Wind turbine	1 300	2,2%	25
Solar PV	990	2,0%	25

Table 11. Assumptions of technology costs in 2030, based on ETRI (version 2014) [18].

To be comparable with the variable costs and revenues computed in our simulations, these costs are annualised over the lifetime of each asset, with a discount rate of 5%. The obtained annualized fixed costs (including CAPEX and OPEX, excluding fuel and CO_2 costs) are displayed in Table 12.

Technology	Annualised costs ($€_{2013}$/MW/y)
OCGT	50 600
CCGT	73 900
Large hydro	220 100
Run of the river	367 100
Wind turbine	116 400
Solar PV	86 700

Table 12. Annualised fixed costs in 2030 used in this study.

[22] For certain technologies, the ETRI proposes data for several sizes of units. In the study, values for PV are based on "Residential solar PV<100 kW" and values for hydro reservoir are based on "Hydropower dam and reservoir 10-100MW – ref value".

One should note that, in the absence of cost curves for Switzerland, we have assumed that all projects have the same cost per MW (i.e. the cost indicated in the above table). In other words, this is equivalent to assuming that all units are treated as new installations when we compare the market revenues to their costs. Therefore, one should not try to generalise the results to all units, in particular for hydropower plants, for two reasons: (i) some of the units have already recovered most of their fixed costs leading to annualised costs far below those quoted in the above table, and (ii) the costs of the projects show large variations. A project-by-project analysis is therefore necessary when assessing the profitability of such projects.

Cost comparisons

The investment costs used in this study are compared to two other sources: the Swiss-Energyscope developed by EPFL and a recent study conducted by the Paul Scherrer Institute (PSI).

EPFL – Swiss-Energyscope

The investment figures used in the Swiss-Energyscope for the year 2035, a national information portal on energy transition developed by EPFL[23], are presented in the following table (assuming an exchange rate of 1 CHF = 0.85 €):

Technology	CAPEX (€/MW)
Large hydro	4040 – 5630
Run of the river	3770 – 4675
Wind turbine	1440
Solar PV	1880

Table 13. 2035 investment costs used in the Swiss-Energyscope (EPFL)

The comparison of the previous table with Table 11 reveals that our assumptions, based on the projections of the Joint Research Centre of the European Commission, are quite optimistic for solar PV, while being of the same order of magnitude for other technologies.

Paul Scherrer Institute

In a recent study, the Paul Scherrer Institute has published a study entitled “Potentials, costs, and environmental effects of electricity generation technologies” for the Swiss Federal Office of Energy[24]. As the PSI study was published towards the end of this project, the costs presented therein have not been taken into account.

The PSI has in particular computed the generation costs of a number of technologies for new installations. In 2035, the PSI projects the following costs for Switzerland (assuming an exchange rate of 1 CHF = 0.85 €):

[23] http://www.energyscope.ch/
[24] http://www.bfe.admin.ch/themen/00526/index.html?lang=de&dossier_id=05238

Technology	Generation costs (€/MWh)
Large hydro	60-255
Run of the river	120-280
Wind turbine	85-145
Solar PV	77-187

Table 14. PSI study costs

These numbers can be compared to the generation costs used in this study that are obtained by dividing the annualised costs (Table 12) by the assumed number of full load hours.

Technology	Full load hours (h)	Generation costs (€$_{2013}$/MWh)
Large hydro	2421	91
Run of the river	5244	70
Wind turbine	1435	81
Solar PV	884	98

Table 15. Generation costs used in this study

As can be read from the two previous tables, our assumptions are found to be at the lower end of the PSI range of costs, and quite optimistic for run-of-the-river units.

Finally, one should not compare the generation costs to the level of support that is currently being granted to project developers (of the order of 95 €/MWh in 2018 for residential solar PV) as the two calculations are based on different points of view. Indeed, when computing the level of support for residential solar PV, the Swiss Federal Office of Energy takes into account the costs that are avoided thanks to self-consumption (the avoided costs correspond to the retail tariff multiplied by the quantity of self-consumed energy). The level of support is then dimensioned so that the project generates an internal rate of return of a few percentage points over its lifetime.

The two comparisons presented above highlight the fact that projecting technological costs at the 2030 horizon is a difficult exercise, and that a great level of care is required when exploiting the conclusions reached in this study (e.g. which technology requires a financial support in order to attract investments).

3.RES net EOM revenues and variability

In this section, we describe the methodology used to evaluate the market remuneration of RES technologies. In particular, we show that the ability to capture market revenues and the dependency of market revenues to weather conditions can significantly vary from one RES technology to the other. All the results presented below are expressed in €$_{2013}$.

a. Revenues assessment methodology

In this study, we assume that the production is dispatched between the fleets according to the European merit order, subject to import/export capacity constraints. The units are taken online in the order of increasing variable production costs[25]. Imports and exports are optimised so that the cheapest technologies are called first, even if from another country.

For a given long-term scenario and a given weather scenario, the wholesale market price at a given hour is found by computing the marginal cost of the most expensive technology that is dispatched during that hour. In practice, the time-series of marginal costs are given by the shadow variables of the hourly demand-supply equilibrium constraints. All online generators are assumed to receive the marginal clearing price (pay-as-clear).

In an EOM context, the hourly generators' revenues are given by the product of their production (in MWh) by the marginal clearing price (in €/MWh). In particular, EOM revenues do not include potential revenues from capacity remuneration mechanism (CRMs) or support schemes.

i. RES generation and correlation to market prices

The ability of a technology to capture market revenues depends on the correlation between its generation profile and market prices. Thus, the market remuneration of variable renewable energy sources, most of which cannot be dynamically controlled, is determined by how underlying weather conditions are correlated with market prices.

The following set of figures illustrates this correlation by comparing hourly and monthly generation profiles to hourly and monthly market prices for different technologies. The results shown here have been obtained using the simulations based on the Vision 1 long-term scenario. The conclusions drawn here also apply to the Vision 3 scenario.

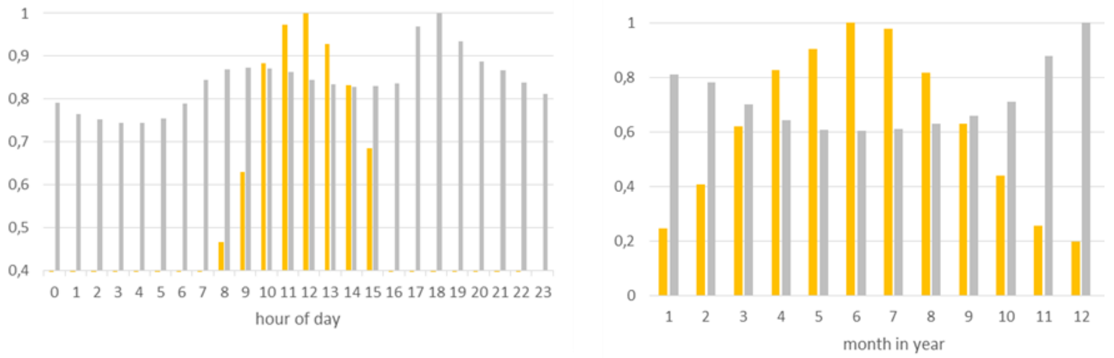


Figure 23. Hourly (left) and monthly (right) normalized average profiles of the PV generation (yellow) and market prices (grey) in Switzerland in 2030. Those are simulation results derived from the TYNDP v1 scenario. Please note that on the left graph, the y-axis has been truncated for illustration purpose.

[25] Technical constraints which may slightly modify a strictly economic dispatch, such as units' minimal load and ramping constraints, are taken into account by Artelys Crystal Super Grid.

Figure 23 shows that solar PV generation and market prices are not very well correlated. In particular, PV generation peaks during summer when prices (and demand) are rather low. One should note that in some southern European countries (Spain, Italy, Greece, etc.), the correlation between annual generation and price is better as the power demand for air conditioning can lead to high prices during summer. The correlation between the production and prices is also found to be poor on a daily time-scale: the production peaks when the demand has already started to decrease after the morning peak.

Figure 24 illustrates that wind power generation is better correlated with market prices. Such a correlation first relies on more steady wind power generation throughout the day. It also benefits from close seasonal profiles observed during the year between wind power generation and market prices.

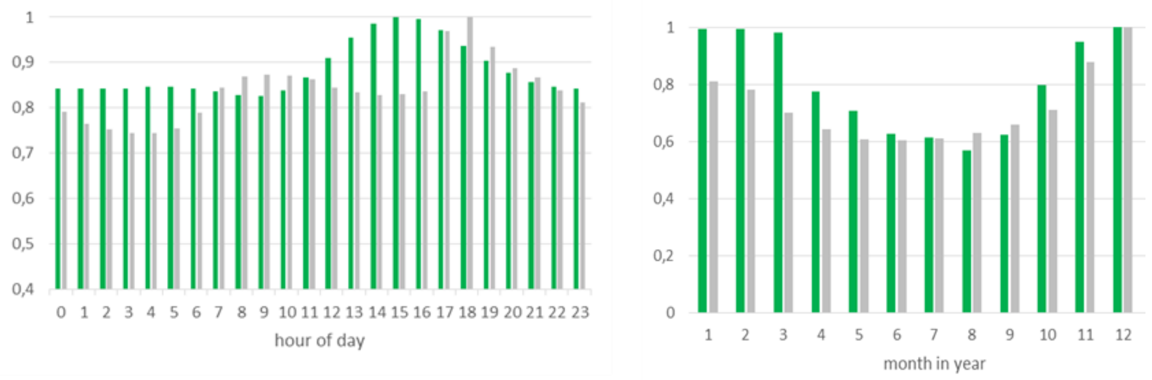


Figure 24. Hourly (left) and monthly (right) normalized average profiles of the wind generation (green) and market prices (grey) in Switzerland in 2030. Those are simulation results derived from the TYNDP v1 scenario.

On the other hand, a peak production technology, such as an OCGT, is designed to provide electricity only at high market price hours, and thus presents a much better correlation between its production and market prices during such hours (see Figure 25).

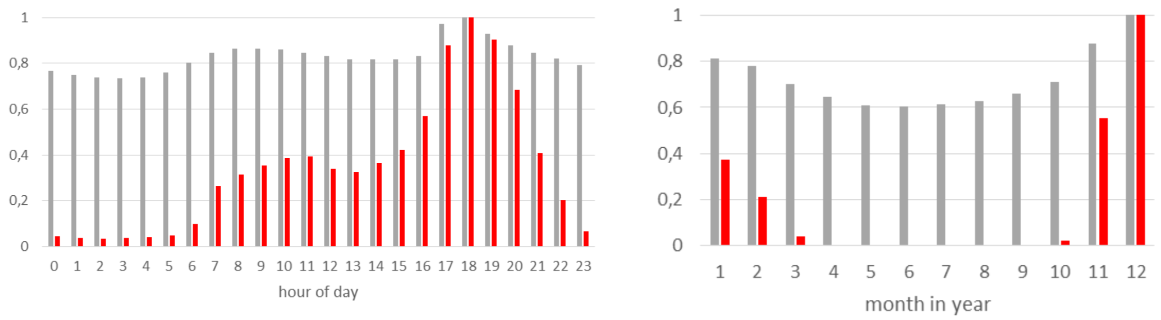


Figure 25. Hourly (left) and monthly (right) normalized average profiles of the OCGT generation (red) and market prices (grey) in Switzerland in 2030. Those are simulation results derived from the TYNDP v1 scenario.

Indeed, as displayed in the above graphs, OCGTs tend to produce mostly in winter (right curve), and at peak hours (around 19h).

The generation of hydro reservoir, displayed on the next two graphs, shows a good correlation with prices at an hourly level since, contrarily to the other RES technologies, its generation can be controlled by the operator due to the presence of a water storage. We can however see on the right graph that at a monthly level, the generation is not very well correlated with the prices, the water inflows peaking mostly in spring and summer.

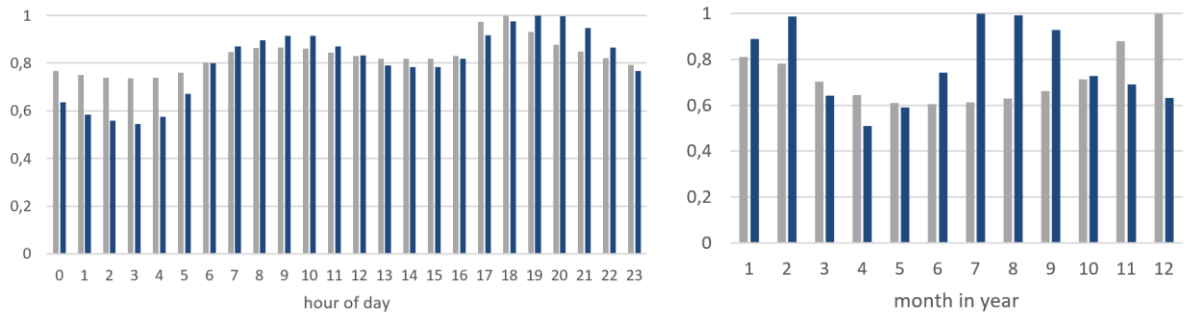


Figure 26. Hourly (left) and monthly (right) normalized average profiles of hydro-reservoir generation (blue) and market prices (grey) in Switzerland in 2030. Those are simulation results derived from the TYNDP v1 scenario.

Hydro run-of-the-river displays the same difficulty at a monthly level, as its generation is also water inflow-dependent. On an hourly level, due to the absence of storage, the correlation between prices and its generation should be lower than the one of hydro-reservoir. Note that due to the absence of data, we have assumed that run-of-the-river generation is constant through the day (which should not be too far from the reality).

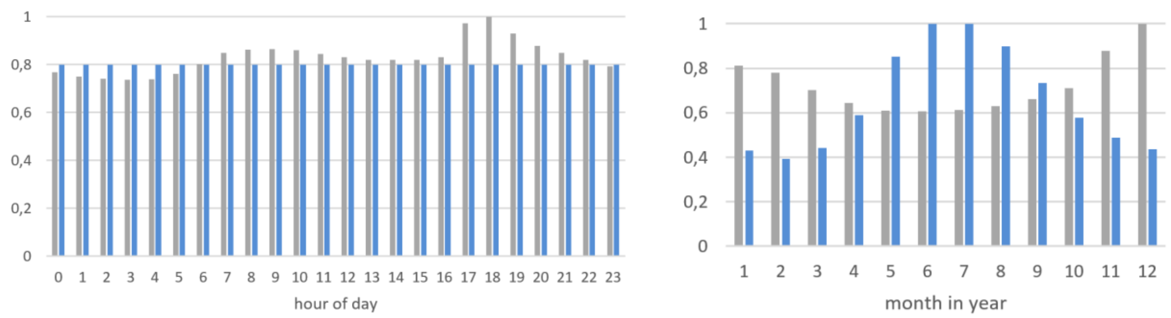


Figure 27. Hourly (left) and monthly (right) normalized average profiles of hydro run-of-the-river generation (blue) and market prices (grey) in Switzerland in 2030. Those are simulation results derived from the TYNDP v1 scenario.

ii. RES EOM annual revenues

For a given long-term scenario (Vision 1 or Vision 3) and a given weather scenario (out of the 50 considered weather scenarios), the annual revenues are computed as the product between the vector of hourly production (in MWh) and the vector of marginal costs (in € per MWh)[26]:

$$\mathrm{AnnualRevenues} = \sum_{t} \mathrm{GeneratedEnergy}_t \times \mathrm{MarginalCost}_t$$

During periods of stress, the power system might be unable to ensure the supply-demand equilibrium is met. During such episodes, the marginal cost of the system strongly increases (scarcity price), potentially up to the price cap of the considered market.

In our model, the marginal costs remain usually close to the variable costs but can attain the value of loss of load (15 k€/MWh) when supply cannot meet demand (either in Switzerland or

[26] For the sake of readability, the weather scenario and long-term scenario indices are omitted in the formula.

in a neighbouring country as scarcity prices can propagate through interconnectors[27]), which is above the assumed Swiss market price cap (3 k€/MWh).

The revenues are thus given by the following formula:

$$\mathrm{AnnualRevenues} = \sum_{\mathrm{t}} \mathrm{GeneratedEnergy_t} \times \min(\mathrm{MarginalCost_t}, \mathrm{PriceCap})$$

where $\mathrm{PriceCap}$ = 3000 €/MWh.

The ability a technology has to capture market revenues can be illustrated by computing its average selling price per MWh. Results for a number of RES technologies are shown in Figure 28. They have been derived from simulations based on the Vision 1 long-term scenario and averaged over the 50 weather scenarios.

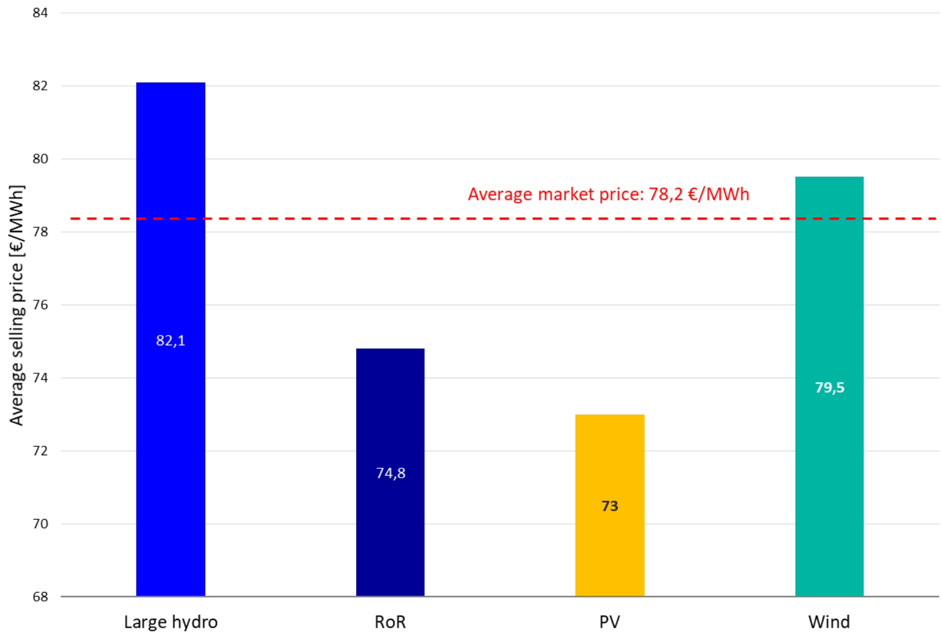


Figure 28. Average selling price for each considered RES technology and average market price (red solid line) in Switzerland in 2030. Results correspond to the Vision 1 long-term scenario and have been averaged over the 50 weather scenarios. These results correspond to a gas price of 37€/MWh, a coal price of 12.5 €/MWh, an oil price of 83.5 €/MWh and a CO_2 price of 31 €/t.

As expected, solar PV has the lowest average selling price. This is explained by the poor correlation between its generation profile and market prices. Controllable technologies on the other hand, i.e. PHS and Large hydro, have average selling prices that are larger than average market price. The average selling price of PHS is particularly high since such a flexible technology is mostly used during peak hours with high market prices.

[27] See Artelys, "*METIS Study S16 - Weather-driven revenue uncertainty for power producers and ways to mitigate it*", 2016

The following figure presents the results for the Vision 3 scenario:

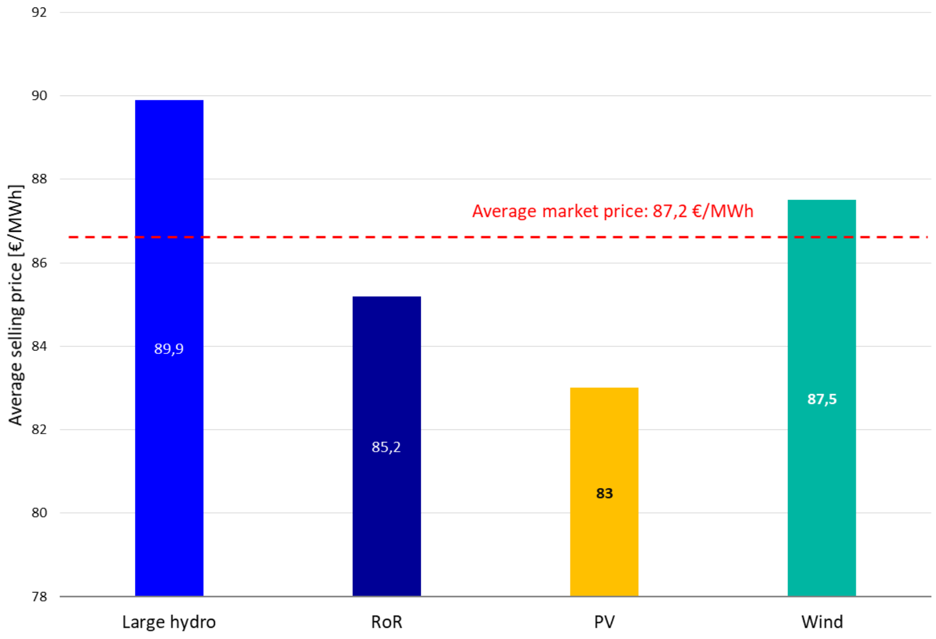


Figure 29. Average selling price for each considered RES technology and average market price (red solid line) in Switzerland in 2030. Results correspond to the Vision 3 long-term scenario and have been averaged over the 50 weather scenarios. These results correspond to a gas price of 28.5 €/MWh, a coal price of 8.0 €/MWh, an oil price of 60 €/MWh and a CO_2 price of 93 €/t.

The same conclusions as previously apply to Vision 3: solar PV has the lowest average selling price among the considered technologies. Due to the poor correlation between its generation pattern and the market prices, solar PV tends not to be able to capture high prices. On the other hand, generation technologies that have a very regular generation profile such as wind power or RoR manage to generate revenues that are close to the market price on average.

One may note that the difference in average market prices between the two long-term scenarios Vision 1 and Vision 3 is quite low given the structural difference of these scenarios. In fact the relatively small difference between the two figures comes from the conjunction of two phenomena which influence the average market price in opposite directions as illustrated by Figure 30.

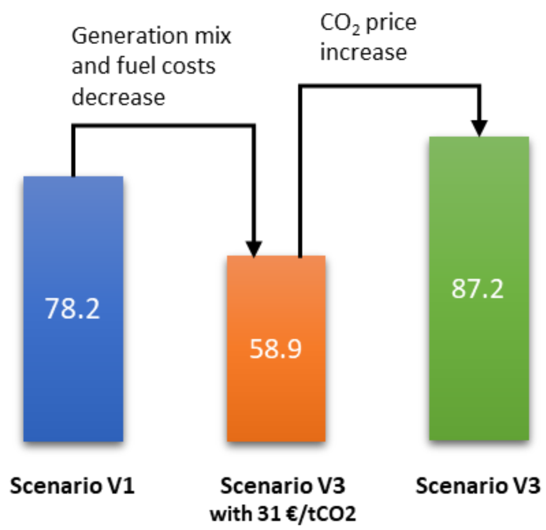


Figure 30. Evolution of average electricity prices in Switzerland in 2030, going from scenario V1 to scenario V3, These results correspond to a gas price of 37€/MWh, a coal price of 12.5 €/MWh, an oil price of 83.5 €/MWh and a CO_2 price of 31 €/t in scenario V1, and to a gas price of 28.5 €/MWh, a coal price of 8.0 €/MWh, an oil price of 60 €/MWh and a CO_2 price of 93 €/t for v3 scenario

Indeed, the increase of European RES capacities and the reduction of thermal capacities, combined with the reduction of fuel costs tends to reduce the average electricity price, going from 78.2 €/MWh to 58.9 €/MWh. However, the associated increase of the CO_2 price from 31 €/tonne to 93 €/tonne pushes the variable costs up by around 20 €/MWh for CCGTs, and by 50 €/MWh for coal units. The combined effect (generation mix, fuel and CO_2 prices) leads to an overall increase of the average electricity price increase from 78.2 to 87.2 €/MWh.

iii. RES EOM net annual revenues

To obtain producers' net annual revenues, one has to subtract the production costs from the annual revenues:

$$\mathrm{NetAnnualRevenues} = \sum_{t} \mathrm{GeneratedEnergy}_t \times [\min(\mathrm{MarginalCost}_t, \mathrm{PriceCap}) - \mathrm{VariableCost}]$$

The $\mathrm{variableCost}$ parameter corresponds to the costs of producing a MWh of electricity, and includes the fuel and CO_2 costs, which are assumed to be identical in every country.

This net revenue corresponds to the **infra-marginal rent** represented on Figure 31 by the part of the green area that is above the supply curve.

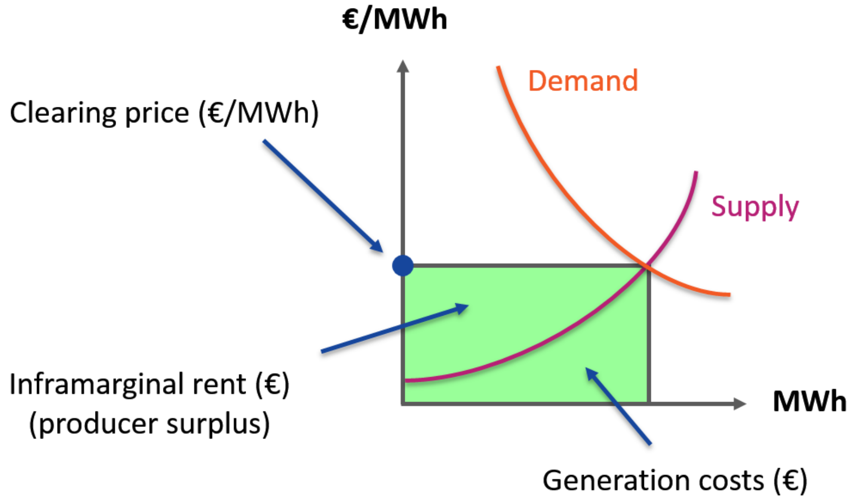


Figure 31. Graphical representation of the infra-marginal rent

The average infra-marginal rents are compared to the annualised fixed costs (which are the sum of annualised CAPEX and yearly O&M) in Table 16. The net annual revenues have been averaged over the 100 considered annual scenarios (50 weather scenarios for Vision 1 and 50 weather scenarios for Vision 3).

Technology	Average net annual revenues (€/MW)	Annualised fixed costs (€/MW)
Solar PV	69 000	86 700
Wind turbine	119 800	116 400
Run of the river	419 800	367 100
Large hydro	207 000	220 100

Table 16. Average infra-marginal rent and annualised fixed costs for the considered renewable technologies.

In the case of solar PV, wind, RoR and large hydro, the revenues are, as expected, close to the product of the annual generation of a MW (which are respectively around 890 MWh, 1440 MWh, 5340 MWh and 2400 MWh according to the assumptions presented in section 2.a.iii) and the average price of energy, here around 83 €/MWh on average over the 2 scenarios and 50 weather scenarios. One may note that solar PV and RoR net annual revenues are slightly below these products, which was expected from our analysis presented in Figure 28 and Figure 29, in which the average selling price of these technologies can be seen to be below the average market price. On the contrary, wind and large hydro net revenues are slightly above the average market price due to their high average selling prices.

Overall, solar PV and large hydro's fixed costs slightly outweigh their revenues in 2030, in average over the weather and long-term scenarios, while wind power and run-of-the-river's fixed costs are found to be slightly lower than their revenues.

In the two figures below, we present the 100 price duration curves (50 curves per long-term scenario).

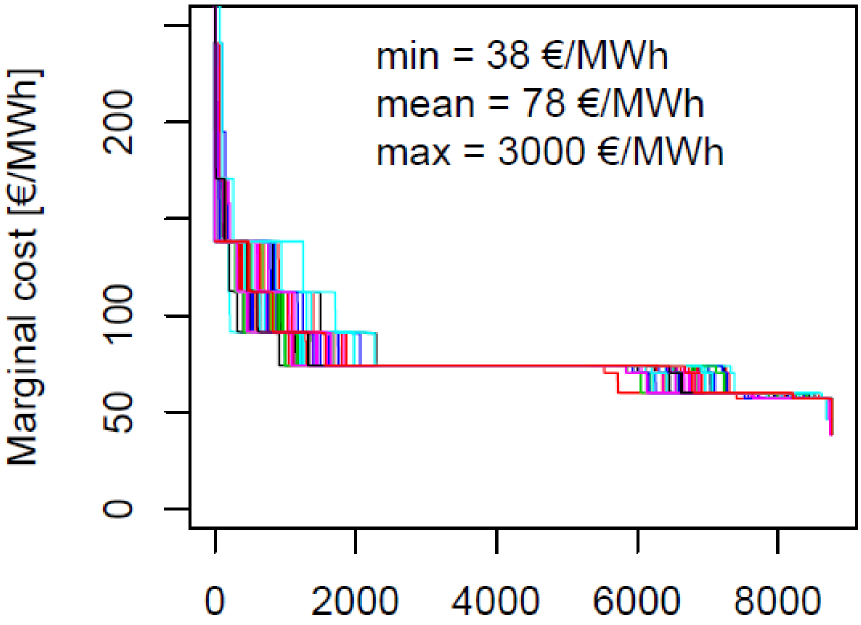


Figure 32. Price duration curves of the 50 weather scenarios for long-term scenario V1

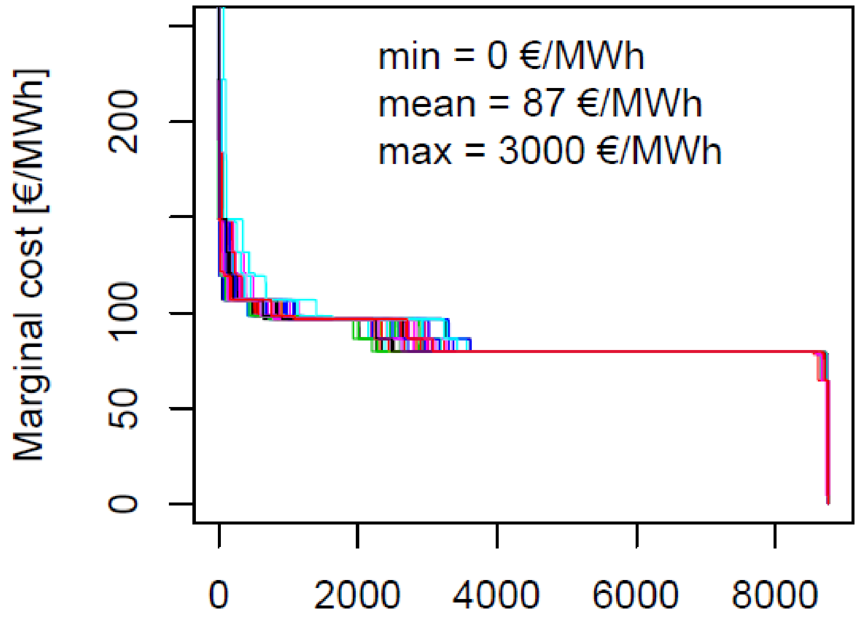


Figure 33. Price duration curves of the 50 weather scenarios for long-term scenario V3

b. Variability of RES net EOM revenues

In the following figures, we show the RES net annual revenues computed for each of the 50 weather scenarios and for both long-term scenarios (Vision 1 and Vision 3) to show for each technology how the revenues vary.

Solar PV

One can read from Figure 34 that solar PV revenues vary depending on the weather variation, up to 10% between the least and most favourable scenario. We also note that the revenues are higher in average in scenario V3 (by around 15%) which was expected given the higher average electricity price.

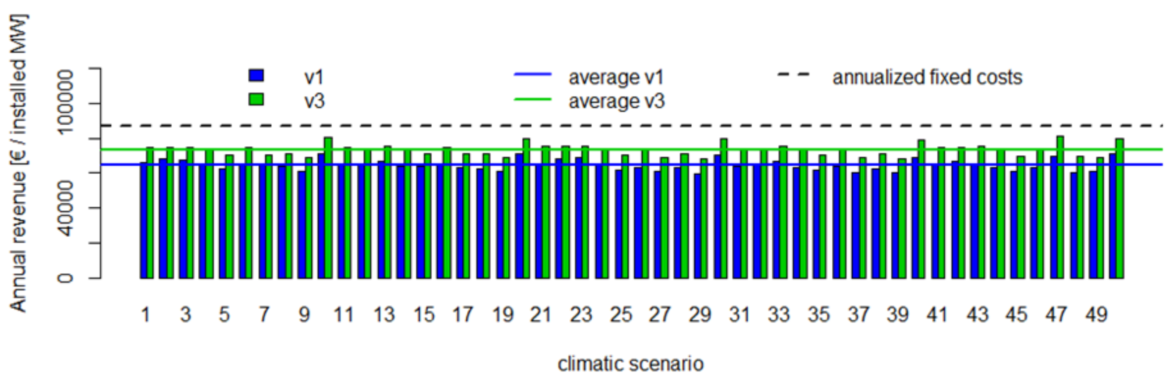


Figure 34. PV net annual revenues per MW for each weather and long-term scenario.

By comparing its average annual revenues and the annualised fixed costs of the project (represented by the dashed lines in the graph), one can note that, without taking into account the risks, solar PV does not recover its annual costs, meaning that the asset is not profitable with the given assumption of costs and power system in 2030.

Wind power

One can read from Figure 35 that wind power generates very regular revenues (except for one scenario, more details below). The difference between V1 and V3 remains due to the average price being different, but in any case the average revenues are higher than the annualised fixed costs, meaning that wind power is profitable in Switzerland in 2030 with our assumption on costs and power system.

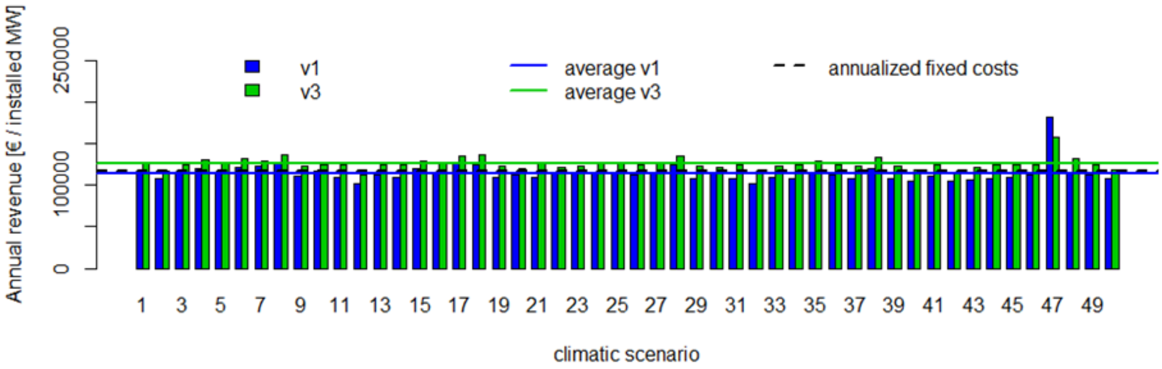


Figure 35. Wind power net annual revenues per MW for each weather and long-term scenario.

Run-of-the-river

The variation of annual revenues for run-of-the-river power plants is more visible than for solar and wind power. The revenues are more irregular due to the fluctuation of generation depending on the weather scenario. Indeed, as we can see in the historical data from SFOE (see [11-14]), the annual generation can vary by 20% depending on the year. In any case, the revenues are almost always larger than the annualised fixed costs meaning that RoR technologies are profitable, risks excluded, in 2030 with our assumptions.

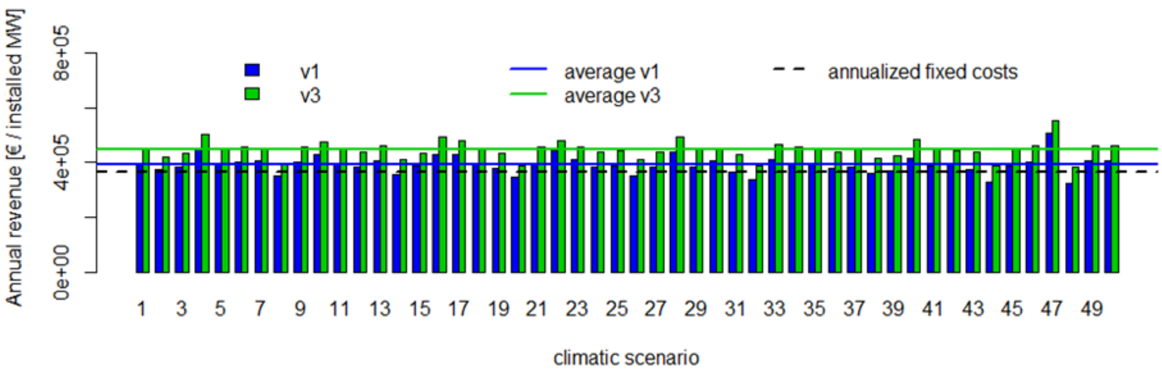


Figure 36. RoR net annual revenues per MW for each weather and long-term scenario.

Large hydro

As displayed in Figure 37, the large hydro assets revenues are impacted by weather variations. This can be explained by the addition of two effects. First, like the RoR units, the generation of large hydro units is dependent on water inflows which are variable from one year to another. This leads to a possible difference in generation of 25% between two years. Secondly, as large hydro units are relatively flexible (controllable), they can better take advantage of market opportunities than RoR units. Their revenues are then also dependent on the occurrence of peak prices and thus on temperature variations. Overall their revenues are quite variable, and it appears that on average they remain lower than their annualised fixed costs, meaning that large hydro reservoirs are not profitable with the considered assumptions.

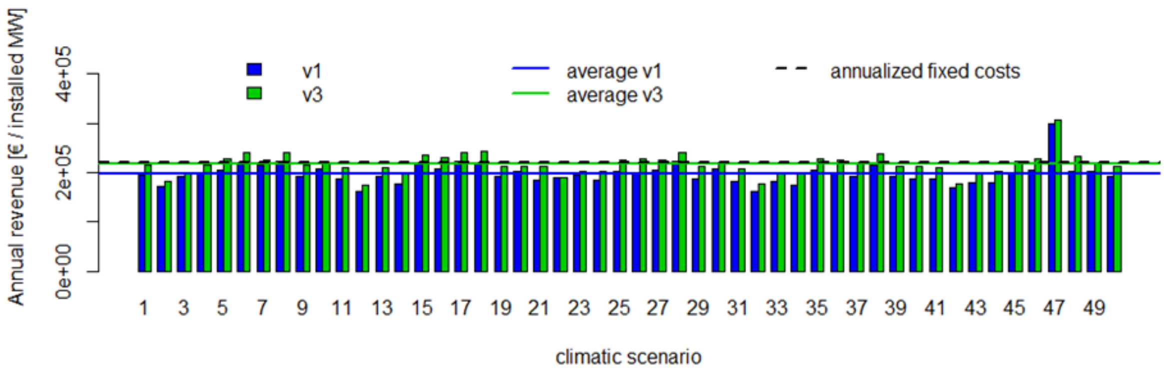


Figure 37. Large hydro net annual revenues per MW for each weather and long-term scenario

Occurrence of scarcity prices

By observing the peak of revenues in weather scenario 47, we identified that the revenues are highly dependent on the occurrence of scarcity prices (as expected). This is in particular the case for RoR, wind and hydro reservoir. Solar PV however is less impacted since scarcity price occur mostly at night, and do not benefit solar revenues.

The number of scarcity hours is displayed in the Figure 38. One may note that overall there is a very low number of hours of scarcity prices in most scenarios. They are mostly concentrated in the least favourable scenario, the weather scenario 47, corresponding to the weather conditions of 2010.

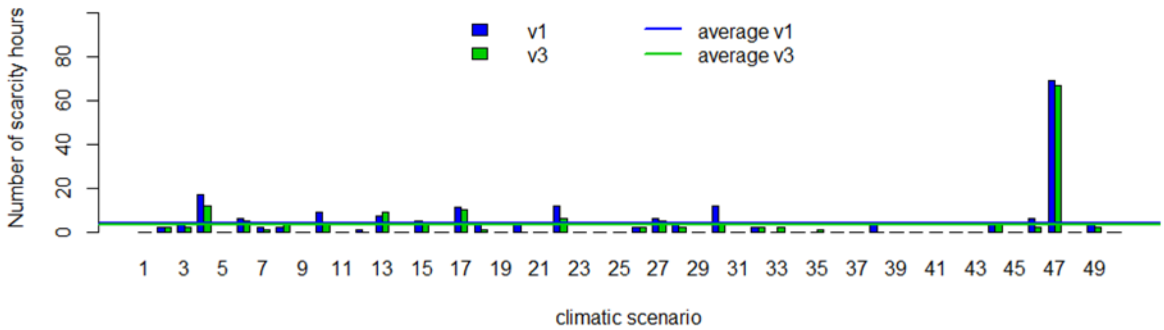


Figure 38. Number of scarcity hours in Switzerland for each weather and long-term scenario

In the case at hand, the large number of scarcity hours in Switzerland in weather scenario 47, comes from a very cold winter, and the high load-temperature sensitivity from France (due to electric heating). Indeed, in France, the very high demand leads to high prices at peak hours, which are transferred to Switzerland since the power systems are interconnected and perfectly coupled in our modelling, as long as the interconnection capacity is not saturated. This thus leads to high prices and revenues for power plants in Switzerland at these hours. This effect has been explored in the METIS Study S16 "Weather-driven revenue uncertainty for power producers and ways to mitigate it"[28].

[28] See https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis for all METIS Studies and Technical Notes.

4. Net lifetime revenues distribution, risks and support schemes

In this section, we describe the methodology used to evaluate the financial support requirements for the RES technologies so that the capacity targets defined by the scenario are reached.

A proper evaluation of the investment value of an asset must include the cost related to the risks felt by an investor. In this research project, we focus on the risks related to the gap of revenues between good situations, where the conditions which are outside of the control of the investor lead to good revenues over the lifetime of the asset, and bad situations, where these conditions lead to low prices and low revenues for the asset throughout its lifetime.

In particular, the conditions we take into account in this study are the weather variations and the long-term European context which both affect prices. To evaluate the risk, the investor thus has to take into account the variation of revenues between all situations, i.e. with the two considered European context, and with different weather variations along the asset lifetime.

For that purpose, we define what we call “lifetime revenues” which are the net revenues an asset would get under one set of conditions (i.e. a chosen European context and an order of weather scenarios over the lifetime of the asset). We then build distribution of these lifetime distributions over 100 000 different conditions. Based on this distribution, a measure of risk is then built: the “risk premium”.

The financial support is then computed so that the net revenues taking account the support covers the fixed costs of the project and the associated risks.

This financial support computation is performed for different support mechanism structures (investment aid, feed-in tariff, feed-in premium and green certificate). The impacts of the structure of the support scheme on risks and the required level of financial support are then assessed.

Note that will the revenues are called “lifetime revenues”, they do not represent actual lifetime revenues of assets which would require a model for each year computed. The approach presented is a static approach based solely on simulations done and revenues computed for 2030 to assess the risk level for a given year. As such the financial support computed do not represent the actual support that should be paid to the investors but an assessment of what is missing taking into account risk so that assets are profitable from a societal point of view.

a. Measuring investment risks

i. Asset net lifetime revenues

The net lifetime revenues of an asset can be defined as the net present value of the cash flows of net annual revenues over its lifespan. It is therefore given by the following formula:

$$\text{NetLifetimeRevenues} = \sum_{n\ in\ [1;Lifetime]} \frac{1}{(1+r)^n} \times \text{NetAnnualRevenues}_n$$

where r is the social discount rate, which is set to 5% (see section 2).

To compute an asset net lifetime revenues one has to consider net annual revenues randomly selected from the considered pool of weather scenarios.

It is important to note that the impact a particular year (i.e. weather scenario) may have on an asset lifetime revenues (e.g. scenario 47 for large hydro reservoirs, see Figure 37) depends on (a) the number of times it is selected during the random sampling and (b) when it occurs (due to the annualisation factor)

Therefore, it is important to compute a large number of lifetime revenue cash flows. In this study, we have generated 100 000 lifetime cash flows. Note that for each estimation, the net annual revenues are being sampled in a unique long-term scenario, either Vision 1 or Vision 3.

An example of the lifetime revenues distribution as obtained after applying the procedure described above is shown in Figure 39 for solar PV. The distribution is bimodal due to higher market prices and revenues in the Vision 3 scenario. The width of each of the distribution components reflects the climatological effect over the lifetime revenue variability in the V1 and V3 scenario respectively.

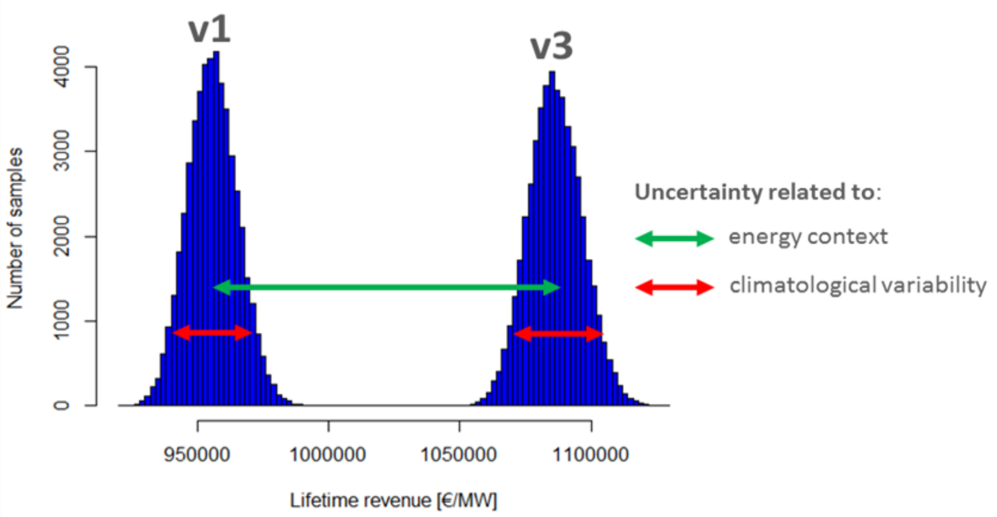
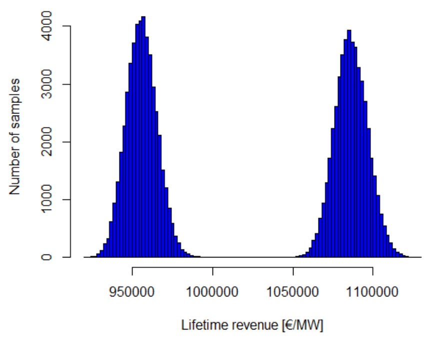
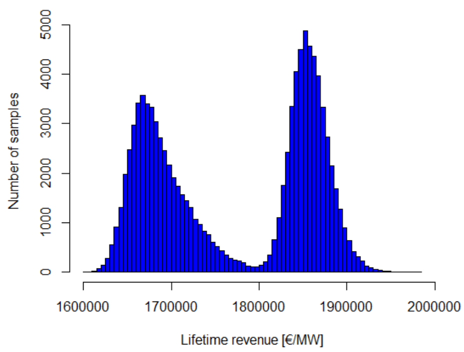


Figure 39. Example of a lifetime revenues per MW distribution derived from 100 000 samplings for solar PV

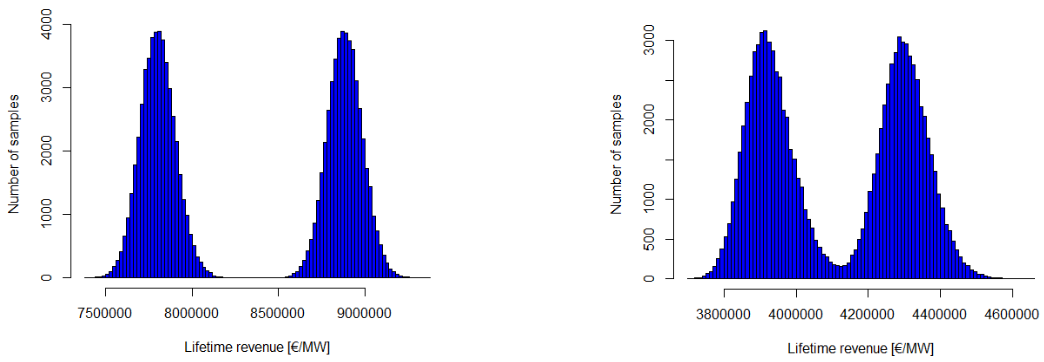
The following figures present the distribution of lifetime revenues for each of the considered technologies.



Solar PV



Wind power



Run-of-the-river **Large hydro**

Figure 40. Distributions of lifetime revenues per MW (based on 100 000 samples) for RES technologies in Switzerland

All the distributions shown above have the same characteristic: the uncertainty related to the long-term evolution of the European power sector is larger than the uncertainty related to the weather conditions during the lifetime of the considered project. It is therefore primarily these long-term uncertainties that should be mitigated by the RES support schemes. One can however also observe that the weather-related risks (measured by the dispersion of each of the distribution modes) can depend on the long-term scenario (e.g. for wind power). This observation advocates for a regular monitoring of the evolution of the European electricity sector, its market design evolutions for a regular review of the parameters of the support schemes. In order not to hinder investments, the principles guiding the review of the support schemes characteristics should be transparent and made easily available to project developers, leading to predictable outcomes.

ii. Risk aversion

To take risk aversion into account, we assume that the value assigned to a given investment project is given by the expected net lifetime revenues from which a risk premium is subtracted:

$$\mathrm{InvestmentValue} = \mathrm{E}[\mathrm{NetLifetimeRevenues}] - \mathrm{RiskPremium}$$

The risk premium is often assumed to depend on the distribution of the expected revenues. The more the revenues are dispersed, the higher the risk premium will be. The value attributed to the investment will be reduced accordingly. The risk premium is assumed to take the following form:

$$\mathrm{RiskPremium} = \alpha * \frac{\mathrm{SemiVariance}(\mathrm{NetLifetimeRevenues})}{2 \times \mathrm{E}[\mathrm{NetLifetimeRevenues}]}$$

where the semi-variance is defined as $\mathrm{SemiVariance}(x) = \mathrm{E}[\min{(x - \mathrm{E}[x], 0)}]^2$

and where α is a parameter measuring the relative importance given to risk by investors.

The risk premium is sometimes computed using the variance instead of the semi-variance. However, from an investor's point of view, the risk consists in getting revenues that are lower than the fixed costs: it is therefore only the left part of the distribution that matters, which is why the semi-variance is preferred to the variance in the case of asymmetric distributions.

This framework is derived from the utility theory and risk aversion formulation originally exposed by von Neumann and Morgenstern, in their seminal book: *Theory of Games and Economic Behavior, Princeton University Press, 1953*. The above formula corresponds to further developments by Arrow (Essays in the Theory of Risk Bearing, North-Holland Amsterdam, 1971). The following paper provides some insight into the experimental and empirical issues: *Holt and Laury, Risk aversion and Incentive Effects, American Economic Review, 2002.*

In the present study, α has been set to 2 which corresponds to a moderately risk averse actor. A particularly risk averse actor may have been modelled through a larger coefficient while an actor less sensitive to risk may use a lower coefficient. One may also refer to the Holt and Laury article cited above, for additional insights into this choice.

iii. Investment values

The average lifetime revenues and associated investment risks are presented for the various renewable technologies in the following table in $€_{2013}$/MW.

	Net Lifetime Revenues	Risk Premium	Investment Value	Lifetime Fixed Costs	Profitability
PV	1 021 000	2 100	1 018 900	1 283 000	-
Wind turbine	1 773 200	2 400	1 770 800	1 723 200	+
Run of the river	8 342 500	18 200	8 324 300	7 295 500	+
Large hydro	4 114 500	4 900	4 109 600	4 374 700	-

Table 17: Average lifetime revenues, fixed costs, risk premiums and investment values for the considered renewable technologies.

By comparing the investment value to the lifetime fixed costs (which are obtained by adding the CAPEX to the net present value of O&M costs), one can assess the attractiveness of the corresponding investment from an investor point of view.

From these results, one can see that the dispersion of the revenue distribution, which is the metric adopted to assess the risk premium, is negligible when compared to the average lifetime revenues. Indeed, the risk premium represents less than 0.3% of the lifetime fixed cost for all RES technologies considered, with the risk premium for RoR being the highest. The relatively low level of dispersion of the revenue distribution (and hence the limited associated risks) is mainly due to the regular revenue of each of the considered technologies.

This relative regularity of revenues comes mostly from two points. First, the yearly generation of RES units varies reasonably (+-10%) depending on the weather scenario. Secondly, the average price, which is the main driver of revenues of base assets (such as the ones we consider in this research project), does not vary much between the two long-term European contexts as we saw in Figure 30.

This is in part due to the scenarios considered, whose combination of CO_2 prices and fuel costs makes close average prices, but also to the modelling choice of considering “adapted” generation mix in terms of gas capacities (which we recall is the recommendation of the IEA and other entities for such studies). Taking two extreme scenarios with high over-capacities or with poor system adequacy will obviously lead to a more erratic behaviors of revenues and thus to higher risks.

In addition, the risk would in fact be much higher for mid-merit and peaking plant as 1.their yearly generation is much more variable depending on weather scenarios and 2. Their selling price does not depend on the average price but on the occurrence of high prices, which also is much more related to the weather scenario considered. This has already been showed in other studies[29].

Technologies that have been assessed as profitable when neglecting risks, namely wind and run-of-the-river, remain profitable when taking risk into account.

Sensitivity to the assumption on fixed costs

The profitability of the investments depend on the assumed level of fixed costs. This assumption can vary from project to project and has a potentially large impact on the investment decision. Therefore, we have replicated the previous exercise with different assumptions on fixed costs, namely a 50% lower and 50% higher cost assumption.

In the first case, which corresponds to a sudden drop in technology costs, the technologies all become profitable as is indicated in the following table. In this case, no support is needed for technologies as they are "in the market".

	Net Lifetime Revenues	Risk Premium	Investment Value	Lifetime Fixed Costs	Profitability
PV	1 021 000	2 100	1 018 900	641 500	++
Wind turbine	1 773 200	2 400	1 770 800	861 600	++
Run of the river	8 342 500	18 200	8 324 300	3 647 700	++
Large hydro	4 114 500	4 900	4 109 600	2 187 400	++

Table 18: Average lifetime revenues, fixed costs, risk premiums and investment values for the considered renewable technologies, in the case of lower fixed costs

However, when looking at 50% higher total lifetime fixed costs assumption, we find that none of the considered technologies is found to be attractive from an investor point of view.

[29] See e.g. Artelys, *Energy transition and capacity mechanisms*, 2015. Available online: http://ufe-electricite.fr/IMG/pdf/france-germany_study_report-2.pdf

Technology	Net Lifetime Revenues	Risk Premium	Investment Value	Lifetime Fixed Costs	Profitability
PV	1 021 000	2 100	1 018 900	1 924 500	- -
Wind turbine	1 773 200	2 400	1 770 800	2 584 900	- -
Run of the river	8 342 500	18 200	8 324 300	10 943 300	- -
Large hydro	4 114 500	4 900	4 109 600	6 562 100	- -

Table 19. Average lifetime revenues, fixed costs, risk premiums and investment values for the considered renewable technologies in the case of higher fixed costs

Summary

The results displayed above demonstrate that, under the assumed potential long-term evolution of the European power sector, fuel and CO_2 prices, and our central assumptions related to fixed costs, a number of RES technologies will have to be financially supported in order for Switzerland to be able to reach its RES targets.

Given that the risks appear to be very low in our estimations, this result mostly comes from the fact that market revenues are too low to cover costs. This could however change if the fixed costs are lower, as is the case in the sensitivity analysis, or if the electricity price increases suddenly for instance due to an increase of the CO_2 price. Analysing the impact of an explicit representation of RES cost curves (investment costs per project or group of projects) on RES deployment and revenues could be a direction for future research.

b. Support schemes

A large variety of support schemes designs have been used throughout the world to support technologies that are either not mature enough to be able to compete on the markets or technologies whose investment costs are so important that investors require a high level of certainty related to the economic conditions in which the project would operate. This section provides a description of the support scheme we have considered in this study, along with the approach we have adopted to model them.

A well balanced support scheme should allow project developers to recover their fixed costs and result in a fair allocation of risks between the public and project developers/operators.

Investment aid

The simplest option to support the deployment of renewables that are not mature enough to compete with other generation technologies on the markets without financial support is to provide project developers with an investment aid.

In the following, we have modelled investment aid as a reduction of the annualised fixed cost of the investment (CAPEX and O&M), leading to a reduction of the lifetime fixed costs:

$$\text{Investment annuity} \rightarrow \text{Investment annuity} - \textbf{Investment aid}$$

The level of investment aid can be set administratively, for example as a given amount per MW, or as a proportion of the investment costs. Under such a scheme, producers are assumed to sell their energy directly on the market (at the market clearing price).

Feed-in tariff (FIT)

The second mechanism we have considered is the feed-in tariff. In such schemes, project operators are guaranteed to receive a fixed payment for each unit of electricity that is generated. The annual revenues are therefore computed as:

$$\mathrm{AnnualRevenues} = \mathbf{FeedInTariff} \times \sum_{t} \mathrm{GeneratedEnergy}_t$$

Compared to the investment aid, the feed-in tariff transfers the risks associated to the annual generation level from the public onto the project operators since the support is proportional to the total energy that is generated. From a project operator point of view, one should note that such a scheme results in all MWh having the same value.

The level of the feed-in tariff can either be set administratively or via auctions where project developers reveal the feed-in tariff that would be required for them to invest. Since the project developers who benefit from a feed-in tariff have no market exposure, the level of the feed-in tariff is usually close to the levelised cost of electricity (LCOE).

Feed-in premium (FIP)

The third support scheme we consider is the feed-in premium. In such schemes, project operators have two different revenue streams: the first one is generated by selling their energy directly on the market, while the second one is a fixed payment per unit of electricity that is generated. The annual revenues are therefore computed as:

$$\mathrm{AnnualRevenues} = \sum_{t} \mathrm{GeneratedEnergy}_t \times \min(\mathrm{MarginalCost}_t + \mathbf{FeedInPremium}, \mathrm{PriceCap} + \mathbf{FeedInPremium})$$

Compared to the feed-in tariff, the feed-in premium transfers further risks onto the project operators since the annual revenues depend on the evolution of market prices. The risks for the project operators are therefore related to both the generated volume and the electricity market prices.

The partial market exposure of feed-in premium mechanisms incentivises project operators to take advantage of the high market prices to increase their revenues (e.g. if they operate a dispatchable technology, or by coupling a battery to a solar PV installation).

Cap and floor premium

A cap and floor premium is very similar to a feed-in premium, in the sense that project operators have to sell their energy on the market while receiving a premium. However, minimum and maximum remuneration levels are defined. The FIP formula applies in all situations but:

- When $\mathrm{MarginalCost}_t + \mathbf{FeedInPremium} < \mathbf{Floor}$, the project operators receive a payment that is larger than the normal feed-in premium, so that the total payment corresponds to the floor value.
- When $\mathrm{MarginalCost}_t + \mathbf{FeedInPremium} > \mathbf{Cap}$, the project operators receive a payment that is lower than the normal feed-in premium, so that the total payment corresponds to the cap value. In cases where the marginal cost (i.e. the electricity market clearing price) is above the cap, the generator has to pay back to the public any remuneration that is above the cap.

This category of support schemes reduces the risks for the investors by setting a minimum remuneration level per unit of generated energy (the floor). The scheme also defines a maximum remuneration (the cap). In particular, when market prices reach values that are above the support scheme cap value, no premium is granted.

Cap and floor regulation mechanisms are not only used to support RES projects, but also to provide large infrastructure project developers with more certainty regarding their future cash flows. For example, the GB regulator Ofgem offers the possibility to interconnection project developers to apply to a cap and floor scheme, so as to encourage investments in electricity interconnectors. Project developers then have to choose between a merchant route (where revenues are not capped, but where the public will not "top up" the revenues in case of low spread levels) and a regulated route under the cap and floor regime.

Figure 41 presents the main differences between the FIT, FIP and cap and floor FIP support schemes. The blue area represents the payment by the public, while the orange are represents the revenues originating from the power markets.

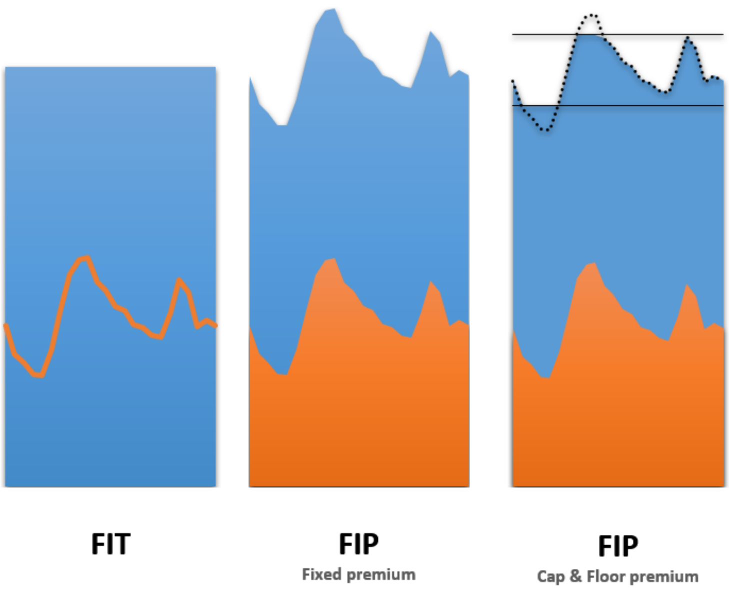


Figure 41. Illustration of the main differences between the FIP, FIP and cap and floor FIP support schemes

Particular versions of the cap and floor support scheme mechanism, where the cap and the floor are set at the same level, are also known as "Contracts for Difference" (CfDs). In such schemes, the only parameter is called the strike price. Such schemes are not only used to support renewables, but also for other generation technologies (e.g. Hinkley Point C nuclear power station in the UK).

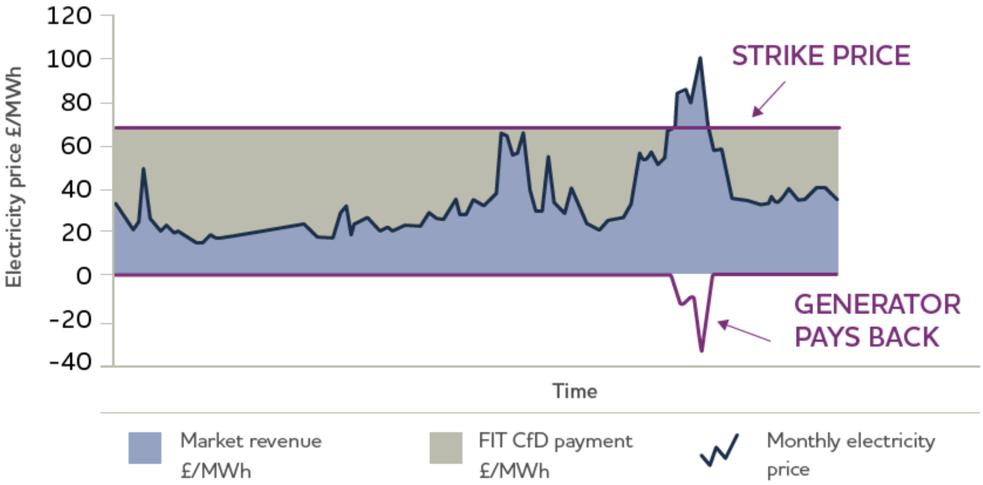


Figure 42. Contract for difference (Source: UK government white paper, July 2011)

Green certificate/technology-neutral feed-in premium

The final support mechanism that is considered in this study is a technology neutral feed-in premium. Under such a scheme, all supported technologies receive the same level of support per unit of generated energy.

In the European Union, technology-neutral auctions are encouraged so as to maximise the effectiveness of the use of public funding. It is the role of the auctions to determine the level of the FIP that will be granted to all technologies.

One can either use the same FIP for all technologies, or use a technology-specific pay-as-clear mechanism to set the level of support. In the latter case, for a joint solar PV and wind auction, the highest solar PV bid that is accepted defines the solar PV FIP while the highest wind bid that is accepted defines the wind FIP. Although this scheme uses different FIP levels for different technologies, the outcome is not the same as the outcome of technology-specific auctions since the share of each technology does not have to be set in advance in a technology-neutral auction.

A number of joint solar PV and wind power pilot auctions are currently being organised by EU Member States, as recommended by the European Commission[30]. Additional measures are often implemented so as to encourage the development of less mature technologies.

For most of the support schemes, the value of the parameters (FIT, FIP, cap, floor, strike price, etc.) can be chosen to depend on the performance of the project operators. For instance, incentives could be granted if the operators satisfy quality of service criteria (e.g. availability levels).

[30] European Commission, SWD (2013) 439 final.

c. Support schemes evaluation

This section presents the level of each of the considered support schemes. The computation done seeks, for each of the support scheme options, the lowest level of support that allows the technology to reach profitability, i.e. the level so that the revenues from the wholesale market and the support are equal to the overall fixed costs and risk premium.

To assess the stability of the support level, this computation is made for the central cost assumptions and for 50% higher fixed costs.

Note that the risk premium may differ depending on the support scheme; indeed, for an investment support for instance, the support level is the same each year, regardless of the generation of the asset. For a feed-in-premium, however, the support obtained by the asset depend on its yearly generation and is thus higher when the yearly load factor is higher. This increases the discrepancy in revenues between a high generation year and a low generation year, which in turn increases the risk premium.

We will however see in this part that, given that the risk is low in the base case, the risk premium remains low for each support scheme

i. Results for the central cost assumptions

As presented above, our results show that two technologies are not profitable (under the assumptions taken on CAPEX and on the generation mix): solar PV and large hydro. For these technologies, the average annual revenues cover respectively 80% and 94% of their annualised fixed costs (see Table 16).

We present below results on support level requirements taking into account the risk, under the presented assumption on CAPEX, generation mix and variability of RES generation. One should note that the difference between the FIT and the FIP values is not found to be the same for all technologies. This is due to the fact that the considered technologies have different abilities to capture market revenues.

Solar PV

Table 20 presents our results for solar PV for the investment aid, FIT, FIP and cap & floor premium support schemes.

Support Mechanism	Support value	Risk premium (€/MW/an)	Annual support per MW (€/year)	Annual technology support (M€/year)	Support for new capacities (M€/year)
Investment support	17 800 €/MW/yr	100	17 800	81.3	51.4
FIT	98.1 €/MWh	< 100	17 700	80.8	51.0
FIP	20.2 €/MWh	100	17 800	81.3	51.4
Cap and floor premium[31]	20.6 €/MWh	100	17 800	81.3	51.4

Table 20. Computed support values in 2030 for the PV technology and the considered support mechanisms, in €$_{2013}$

[31] Cap and floor values are fixed respectively to 80% and 120% of the FIT value. In this case, it corresponds to 78.5 €/MWh and 117.7 €/MWh respectively.

In the previous table are presented:

- The **support value** and **risk premium**, computed for each support scheme as explained above,
- The **annual support per MW**. For the FIP, it is simply computed as the product of the generation of 1 MW of PV and the support value. For the FIT, as it replaces entirely market revenues, it is computed as the difference between the support and the market revenues for 1 MW.
- The **annual technology support**, computed as the product of the annual support per MW and the capacities in 2030 as specified in Table 8. It represents the costs for the system if all capacities (old or new) are eligible for support.
- The **support for new capacities**, computed as the product of the annual support per MW and the capacities built between 2017 and 2030 as specified in Table 8. It represents the costs for the system if only new capacities are eligible for support.

In particular, the investment aid that would be required in order to attract investments would be of around 17 800 €/MW per year. This corresponds to around 20% of the revenues captured by solar PV installations. In the case of a guaranteed remuneration per MWh (FIT), the total remuneration would have to be of around 98 €/MWh in order for a project to attract investments. When actors directly sell their energy on the market, a feed-in premium of around 20 €/MWh is found to be required.

Large hydro

Table 21 presents our results for large hydro assets for the investment aid, FIT, FIP and cap & floor premium support schemes.

Support Mechanism	Support value	Risk premium (€/MW/year)	Annual support per MW (€/MW/year)	Annual technology support (M€/year)	Support for new capacities (M€/year)
Investment support	13 300 €/MW/yr	200	13 300	109	0.4
FIT	91.3 €/MWh	< 100	13 100	107	0.4
FIP	5.5 €/MWh	200	13 300	109	0.4
Cap and floor premium	5.0 €/MWh	200	13 300	108	0.4

Table 21. Computed support values in 2030 for the large hydro technology and the considered support mechanisms, in €$_{2013}$.

Since large hydro units are almost able to cover their fixed costs, the investment aid that would be required in order to attract investments would be of around 13 300 €/MW per year. In the case of a guaranteed remuneration per MWh (FIT), the total remuneration would have to be of around 91 €/MWh in order for a project to attract investments. When actors directly sell their energy on the market, a feed-in premium of around 5 €/MWh is found to be required.

Regardless of the support scheme, the revenues from the support reaches around 6% of the total revenues received by large hydro units. This result is driven by the 2030 market price obtained in the simulations (around 80 €/MWh on average) and by the assumptions taken for CAPEX which are likely to be on the lower end of the range of current values for CAPEX for large hydro units. Finally, one should note that we only consider a single average value of fixed costs per technology in this study (in the absence of cost-curves for Switzerland). The costs of large hydro projects can be very heterogeneous, as they often depend on the local situation.

ii. Results for the +50% cost sensitivity analysis

As mentioned above, the support levels strongly depend on the cost assumptions. The sensitivity analysis presented in this section considers a 50% increase of all costs (CAPEX and O&M). The comparison between the investment values and fixed costs has shown that none of the considered technologies is able to cover its fixed costs, and therefore all RES technologies would require a financial support in this scenario (see Table 19).

As can be read from the following table, the support required by solar PV and large hydro technologies may substantially increase if the fixed costs were to increase by 50% (+243% for the PV and + 825% for the large hydro). One should treat these figures with cautions since the large increases are mainly due to the low level of support needed in the central case (especially for large hydro).

Support Value	PV	Wind	RoR	Large hydro
Investment (€/MW/year)	61 100 (+243%)	55 000	132 000	123 000 (+825%)
FIT (€/MWh)	147 (+50%)	122	105	137 (+50%)
FIP (€/MWh)	69.1 (+243%)	38.3	25.1	51.2 (+825%)
Premium with Cap&Floor (€/MWh)	69.9 (+240%)	39.9	26	52.7 (+961%)

Table 22. Computed support values in 2030 for the various RES technologies and support mechanisms when considering an increase of fixed costs by 50%. The percentages in parenthesis show the increase in support value when compared to the default assumptions, in €2013.

iii. Green certificate

The cost sensitivity analysis has revealed that all technologies may require a financial support in order to be profitable. The level of support presented above depends on the technology: some technologies such as solar PV require larger premium than others (e.g. wind power).

In this section we study the impact of adopting a “green certificate” mechanism, or a technology-neutral feed-in tariff. Such a support would provide the same feed-in premium per MWh to all RES technologies.

Due to its technology-neutrality, such a mechanism will provide investment incentives that would result in a generation mix that is different from the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario. Indeed, if we were to distribute the same level of FIP to all technologies in the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario, we would have to select the highest FIP among all technologies to ensure that all technologies are profitable. In such a case, some technologies (the ones that require the lowest levels of support) would likely be very profitable, and thus attract more investments. As a consequence the green certificate support scheme would not be able to reproduce the RES portfolio in the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario, but would result in a different RES portfolio.

In order to determine what portfolio would be obtained, we have optimised the RES portfolio with the constraint that the total RES production should be equal to the RES production in the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario (27.5 TWh/year on average over the 50 considered weather scenarios).

In the following, we present the result of a capacity expansion planning exercise where we have considered the optimal portfolio of solar PV, wind power and run-of-the-river[32]. Moreover, we assumed that the 2030 capacities of solar PV, wind power and run-of-the-river should be between the 2017 and 2050 *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario projections. The lower and upper bounds along with the capacities obtained by the optimisation process are shown in Table 23.

Capacities (MW)	PV	Wind	RoR
Lower bound (2017 projection)	1679	372	3889
Upper bound (2050 projection)	12575	2967	4464
Optimised capacities	1679	1785	4464

Table 23. Estimated capacities for PV, Wind and RoR technologies resulting from the optimisation process. Lower and higher bounds respectively come from 2017 and 2050 Prognos projections

These results show that the RoR potential is fully used, as this technology has the best profitability among all three technologies. As the installation of further RoR capacity is not enough to satisfy the total RES production constraint, the model chooses to invest in wind power. Finally, as solar PV is the less profitable technology, and that investments in RoR and wind power are sufficient to ensure the total RES production constraint is met, no further investments in solar PV is made by the model.

The fact that technologies are selected in order of profitability is no surprise, since the composition of the Swiss power system has little influence on the market prices (see next section). However, if one were to introduce such mechanisms at an European level, it is likely that a more complex outcome would materialise, as the penetration of a technology can cannibalise the revenues of another one (for example, if the capacity of solar PV were to substantially increase, the overabundance of production at noon would likely depress the prices and would therefore reduce the market revenues per MW of installed solar PV).

In the case of Switzerland, the constraints on the capacities of each technology may prevent the optimization from converging toward a solution representing an adequate mix between the three considered technologies (where no technology saturates one of the lower or upper bounds). In these conditions, the simulation of a green certificate mechanism may not end up being a cheaper alternative to a FIP mechanism.

Results

As can be read in Table 23, the model does not invest in further solar PV capacities when given the choice to invest in solar PV, run-of-the-river or wind power to meet the RES targets: the optimal capacities are found to be the ones that already exist. Indeed, since we only consider a single cost per technology, a diverse portfolio of technologies is unlikely to emerge from this optimisation. In the case at hand, the model first chooses to invest in the most profitable technology (RoR). As the generated power with the additional RoR capacity does not allow Switzerland to reach its RES generation targets, the model invests in further wind

[32] Large hydro has not been included as its potential is relatively limited and would likely require a dedicated mechanism should a technology-neutral support be adopted for PV and wind.

power capacity until the target has been reached. The order in which technologies are selected is highly dependent on the cost assumptions.

	Price-fixing technology	Support value (€/MWh)	3-techno support (M€/y)	Savings with respect to FIP (M€/y)
Green Certificate	Wind	38.3	193	58

Table 24. Results for the Green Certificate support evaluation, where the capacities of solar PV, wind and RoR have been optimised.

In the previous table:

- **3-techno support** is the product between the computed support value and the installed capacities.
- **Savings with respect to FIP** is the difference between the computed 3-techno support and the support with FIP mechanisms for each of the technologies as computed in section 4.

We can note that, when the support is only distributed to the selected technologies (or to the technologies that have been cleared in an auction), the RoR and wind capacities are larger than the ones of the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario (in order to compensate for the low penetration of solar PV). As a result, more support is required for these technologies, but this additional support requirement is found to be more than compensated for by the absence of new solar PV installations to support. According to our results, such a green certificate support mechanism would result in savings of around 58 M€/year. The results presented in this section do not take into account the attractiveness (or lack thereof) of the different technological solutions: the low level of public acceptance of wind turbines and the relative ease with which solar panels can be deployed compared to the other solutions are such that the economically optimal solution might not be easily reached. Further analysis would be needed to take into account the impact of non-economic effects on the optimal portfolio of generation technologies.

5. Impact of RES deployment on their revenues in Switzerland

In this section, we show that the penetration of RES capacities in Switzerland has a low impact on the electricity prices in Switzerland. In particular, the cannibalisation effect between technologies is low: the share of the demand that is met by either solar PV or wind power would have to dramatically increase to have a sizable impact on the revenues of the other technologies, or on themselves. In large systems, one would expect that a further deployment of solar PV or wind power would exert a negative pressure on market prices, and thus reduce the EOM revenues of all power plants. However, we find that due to the relative sizes of the Swiss and European power systems, Switzerland can be described as a price-taker. As a consequence, the Swiss generation mix has little influence on the profitability of the Swiss assets.

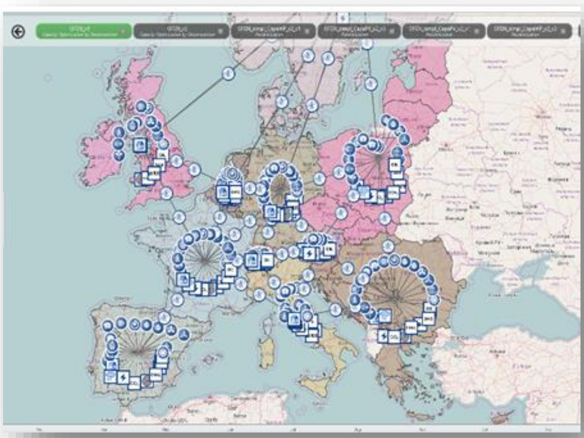
In order to illustrate this effect, we consider penetrations of solar PV and wind power that go far beyond the values of the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario.

a. Methodology

Increasing the penetration of RES technologies in Switzerland may displace more expensive resources at the European level. Indeed, RES generation can replace some of the production of baseload or mid-merit technologies. Thanks to the high level of interconnection between Switzerland and its neighbours, a further deployment of RES technologies in Switzerland will impact the generation output of expensive units at the European level (as long as the interconnection are not saturated), and therefore have a potential impact on European market prices.

In this section we investigate the impact of a further deployment of RES technologies in Switzerland on the revenues of the Swiss assets. Since the description of the dynamical interaction with neighbouring countries is an essential ingredient of the assessment, we have first performed a sensitivity analysis regarding the mode of representation of the neighbouring countries. The following two systems have been compared:

- **Complete European model –** In this model, all countries belonging to the ENTSO-E are explicitly represented. Each country is characterised by its generation mix, hourly demand time-series (50 annual weather scenarios), etc. The net transfer capacities of the interconnectors linking the modelled countries are based on the ENTSO-E TYNDP values.



- **Simplified model –** In the simplified model, Switzerland is explicitly modelled, while all the other zones are represented by zonal market prices. The Swiss power system can then buy electricity from these zones or sell electricity to these zones as long as the interconnection capacities are not saturated. The zonal market prices have been obtained by running the complete European model.

The performance of simplified models is found to be excellent when studying small deviations from the complete European model. However, in the case at hand, before using a simplified approach we wanted to ensure that simplified models are also suitable when increasing the penetration of RES technologies in Switzerland far beyond the values of the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario.

We have first compared the EOM revenues of solar PV and wind producers with normal and high penetration levels of solar PV in the two model configurations. The results for the Vision 1 long-term scenario are shown in Table 25.

EOM revenues (€/MW)	PV	Wind
Complete – NEP C&E scenario + Vision 1	65 066	123 585
Simplified – NEP C&E scenario + Vision 1	65 213	123 594
Complete – PV capacity x 10	50 442 (-22%)	116 802 (-5%)
Simplified – PV capacity x10	52 375 (-20%)	119 762 (-3%)

Table 25. Evolution of wind and PV revenues in the complete and simplified models

From the first two rows of Table 25, we see that the performance of the simplified model is excellent: we accurately reproduce the revenues of PV and wind producers (and other technologies too, although they are not shown here). This is not surprising since the prices in the neighbouring zones have been set by running the complete model.

In addition, even if one were to assume a massive increase of the solar PV capacity in Switzerland (by a factor 10, which would lead to a generation mix with 60% of PV generation), wind and PV decrease in revenues would remain very similar in both models. Indeed, PV producers' revenues are found to decrease by 20% in the simplified model, while they decrease by 22% in the complete model. Similarly, the wind power producers' revenues decrease by 3% in the simplified model instead of 5% in the complete model.

This result by itself is interesting: the fact that revenues remain almost identical with a tenfold increase of the solar PV capacity in both models is an indicator that the Swiss RES generation capacity is too small to significantly impact the marginal costs of other countries through exports. Given that the performance level of the simplified model is only very moderately impacted by very high RES deployments in Switzerland, we have adopted it for the following evaluations.

b. Results

In this section, we present our results related to the evolution of the revenues of the various production technologies in the Swiss electricity mix for different levels of wind power and solar PV deployment. The two indicators that we have observed are the annual revenues and the value factor (or the ability of a technology to capture high market prices).

i. Annual revenues evolution

First we present our results related to the evolution of the annual revenues by technology when the penetration of solar PV and wind power increases up to very significant levels (beyond the levels considered in the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario).

The results are presented independently for the two long-term scenarios considered in this study (which only apply to the rest of Europe, Switzerland being assumed to adopt the *Neue Energiepolitik C&E Sensitivitätsanalyse Photovoltaik 1* scenario capacities in all cases): Vision 1 and Vison 3. Figure 43 presents the evolution of the revenues per MW for the Swiss generation units when the share of PV increases (left) and when the share of wind increases (right).

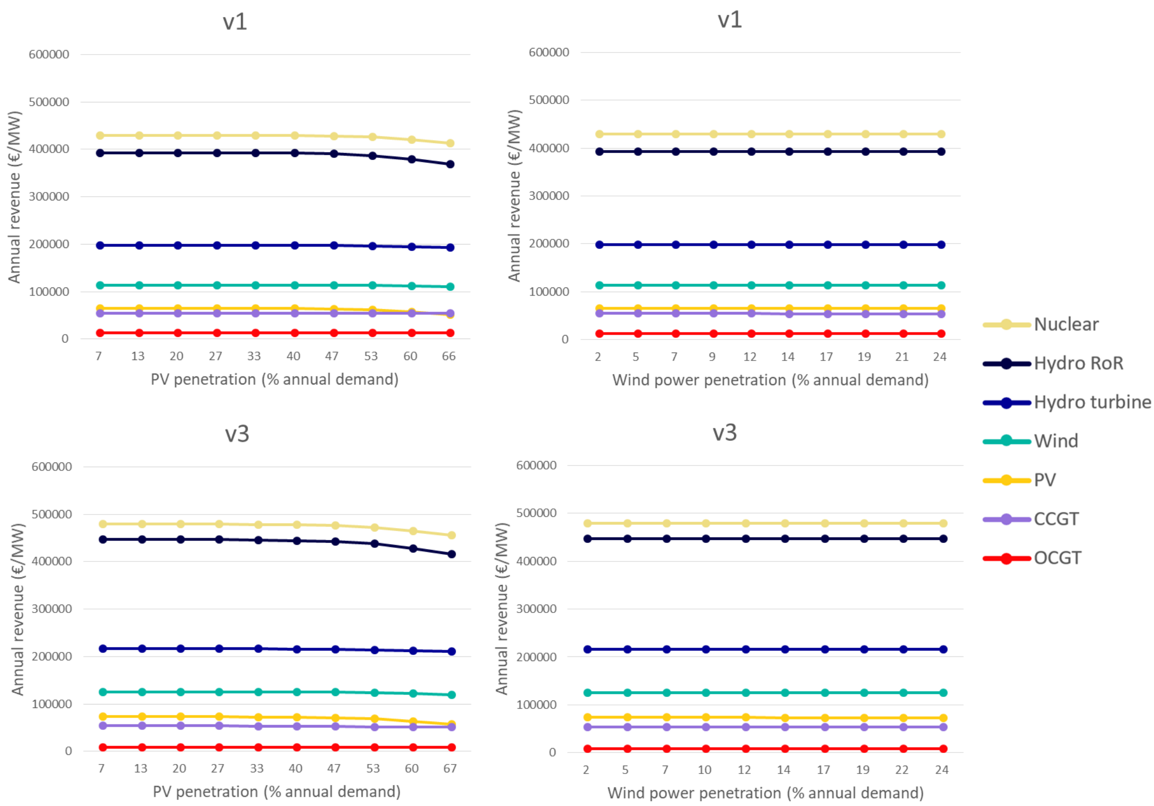


Figure 43. Evolution of the average annual revenue (in € per installed MW) depending on the PV (left) and wind power (right) penetration, for all technologies in the Vision 1 and Vision 3 long-term scenarios

We can observe from these figures that the Swiss producers' revenues have a very low sensitivity to the share of wind power and solar PV penetration in Switzerland. Only in extreme situations, when increasing the solar PV penetration by a ten-fold factor, can we expect to see a little variation of the revenues of solar PV, nuclear and hydro RoR due to the cannibalisation effect. This result shows that the further deployment of RES technologies in Switzerland[33] is unlikely to impact the remuneration levels of the other technologies.

The fact that the further deployment of wind power has no impact on the revenues of the other technologies is due to the fact that the wind production is very evenly distributed (especially at the daily level). Its impact is therefore diluted over the whole year. In contrast, the production by solar PV is characterised by a clear daily cycle. When the penetration of solar PV substantially increases, the following impacts can be expected:

- **Solar PV displaces more expensive resources** – A number of technologies can potentially be impacted by the increase in solar PV capacity. As a consequence, some of these technologies will see their production per MW decrease.
- **Solar PV exerts a negative pressure on the midday Swiss prices** – When the penetration of solar PV increases significantly, lower market prices can arise at midday

[33] As is written in the beginning of the section, this does not mean that the deployment of RES technologies has no impact on revenues in general. A significant increase of RES capacities throughout Europe will definitely lead to a general reduction of revenues, everything else supposed unchanged. The results only show that the capacity of RES in Switzerland is too small to affect the prices at a European scale.

due to the impact of solar PV on the merit order. As a consequence, technologies that generate power during these hours see their revenues decrease (e.g. solar PV itself),

The combination of these two phenomena explains the impacts on the revenues per MW: a lower production per MW and a lower remuneration per MWh both lead to negative effects on the revenues per MW.

ii. Value factor evolution

The second metric that we use to illustrate the impact of a further deployment of solar PV and wind power is the value factor, which is given by the ratio of the average selling price over the average market price.

$$\text{Value Factor} = \frac{\text{Average Selling Price}}{\text{Average Market Price}}$$

The average selling price of a technology is given by the average of the market price weighted by the level of generation:

$$\text{Average Selling Price} = \frac{1}{\text{Annual Generation}} \sum_{h=1}^{8760} \text{Generation}_h \times \text{MarketPrice}_h$$

while the average market price is simply given by:

$$\text{Average Market Price} = \frac{1}{8760} \sum_{h=1}^{8760} \text{MarketPrice}_h$$

In other words, the value factor measures the performance of a technology compared to a hypothetical situation where its energy would be sold at a constant price (the average market price). If a technology can dispatch its production during periods of high prices, its value factor will be larger than one, while if it tends to produce during periods where the price is lower than its annual average, the value factor will be lower than one.

The usual value factors for baseload technologies (e.g. nuclear power plants) will therefore tend to be close to 1, as they produce all year round. Mid-merit capacities (e.g. CCGTs) will select hours when prices are high, and finally peaking plants (e.g. OCGTs) will have large value factors.

The evolution of value factors due to a further deployment of solar PV and wind power are presented in Figure 44 for the case where the share of PV increases (left) and when the share of wind increases (right), and for both considered long-term scenarios (Vision 1 and Vision 3).

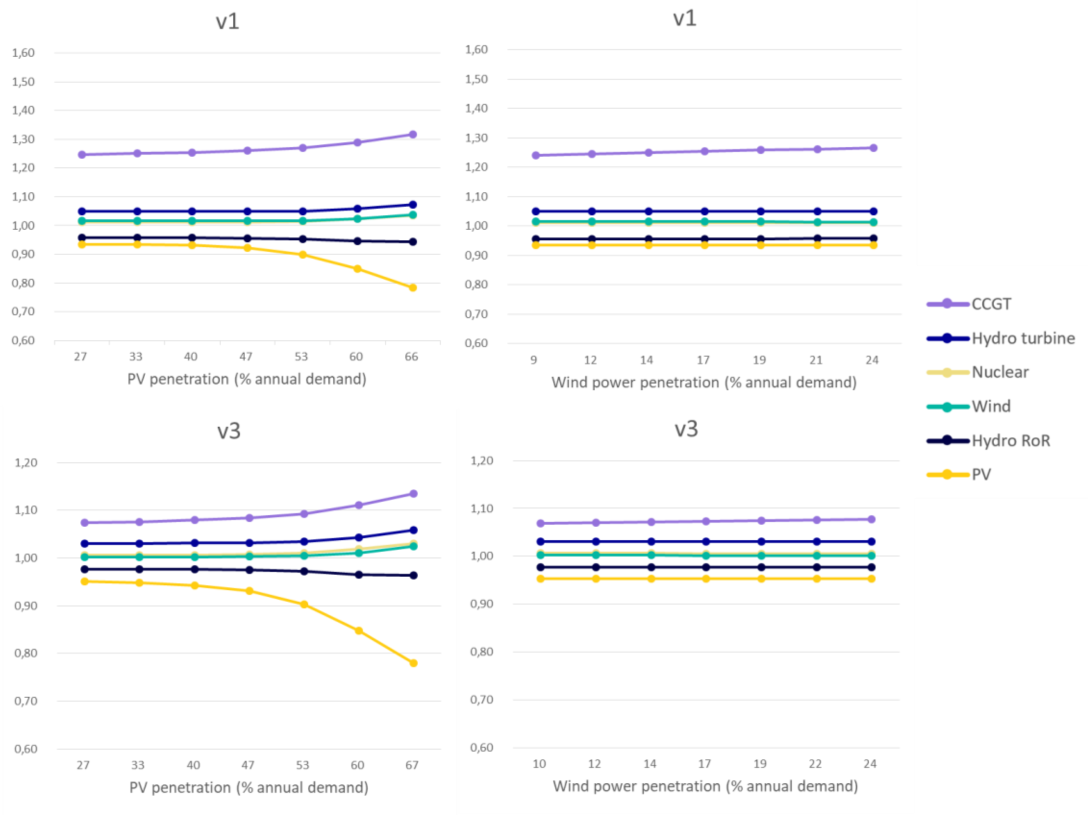


Figure 44. Evolution of the average value factor depending on the PV (left) and wind power (right) penetration, for all technologies in the Vision 1 and Vision 3 long-term scenarios

Note for the sake of readability, the value factor of OCGTs is not displayed in the graph. As expected, the value factors of OCGTs are high (2.8 in Vision 1, 6.5 in Vision 3), as its average selling price is significantly higher than the average price of electricity. Its behaviour depending on the RES penetration is the same than CCGTs': it increases when the RES capacity becomes high since the average electricity price drops.

The analysis of Figure 44 reveals that, as could be expected after the analysis of the annual revenues, a large deployment of wind power has almost no impact on the value factors of the Swiss technologies.

In the case of solar PV, the computation of the value factor allows to illustrate the "cannibalism" effect of the PV technology on its own remuneration due to the negative impact on the midday market prices (average selling prices) being larger than the impact on the average market prices.

It is interesting to note that the value factor of wind power slightly increases as the penetration of solar increases despite its non-dispatchable nature. Indeed, the wind turbines generation patterns are such that the decrease of their average selling price is lower than the decrease in average market price.

For controllable production technologies, a decrease of the average market price does not necessarily lead to a decrease of their average selling prices (since it is unlikely that CCGTs or OCGTs run when solar PV generates its power). It is thus not surprising to observe that both large hydro and CCGT technologies see their value factors increase for very high PV penetrations. Finally, PHS tends to cycle more often, but with lower selling prices since it is able to take advantage of new arbitrage opportunities by buying power during the hours where PV generation is important.

Finally, one should note that the low sensitivity of RES revenues to RES penetration levels advocates for setting a target on the level of RES that should benefit from support schemes.

Indeed, as the level of remuneration per MW is almost constant when solar PV and wind power increase their market shares, there is no self-regulation mechanism that would prevent a large amount of projects to request public funding.

In other words, an oversizing of the support scheme may result in overcapacity if no target capacity is set beforehand. One recognised way to set targets and reach them cost-efficiently is to organise auctions (that may either be technology specific, or technology neutral, as advocated for by the European Commission). Through an auction, the market participants reveal the value of one of the parameters of a support scheme (e.g. the value of the FIP that they would like to receive). In most cases, these auctions adopt pay-as-bid clearing practices.

6.Conclusion

This study aims at assessing the risks impacting market revenues of RES-e producers (namely wind, solar PV, hydro run-of-the-river and large hydro), and how the design of a RES support scheme can mitigate these risks. For that purpose, we used the Artelys Crystal Super Grid model, which allows to jointly optimise flows and generation across Europe for a given year at an hourly time step. The model has been adapted to take into account weather variations, in the form of 50 hourly time series for consumption, and 10 hourly time series for RES-e load factors across Europe, as is done in the METIS project. Capacity and yearly consumption data is based on two ENTSO-E TYNDP scenarios (V1 and V3) for all countries except Switzerland. These two scenarios allow to take into account the risks related to the evolution of the energy context, which are key for the evolution of the market prices and thus of the market revenues. As for Switzerland, a specific configuration has been done to take into account the *Neue Energiepolitik* scenario for demand and the *C&E Sensitivitätsanalyse Photovoltaik 1* scenario for the generation portfolio. The model has also been updated to take into account SFOE historical data, especially for hydro load factors and storage constraints which also depends on the weather scenario. While it has not been done in the project, this model could be used for instance for studies on resource adequacy, synergies between different energy vectors (joint modelling of gas and electricity networks), or design of an optimal portfolio of flexibility solutions to integrate renewables costs efficiently.

The analyses conducted show first that the average selling price of large hydro and wind power is higher than those of hydro run-of-the-river and solar PV, which means that their generation profiles occurs more frequently in situation where prices are high, i.e. when the power system needs it.

The cost-benefit analysis carried out during this project has revealed that solar PV and large hydro are not profitable under our central cost assumption from the point of view of an investor wanting to sell the generated energy on the electricity market in 2030. On the other hand, we find that wind power and run-of-the-river units are able to capture sufficient revenues to recover their fixed costs.

As an investment decision is not only based on the expected level of revenues, we have analysed the distribution of these revenues when one considers contrasted scenarios of the evolution of the European power sector and a range of climatic scenarios. According to our analysis, the risks have a low impact on the profitability of the considered technologies and on the required support for unprofitable technologies. The evaluation of the risks has demonstrated that the evolution of the European power sector has a much greater influence on revenues over the lifetime of an investment than the weather variability. This fact advocates for a regular monitoring of the development and expected impacts of European policies and measures, so as to be able to transparently review the parameters of the Swiss support schemes.

Furthermore, the analysis conducted during this project has shown that Switzerland can be characterised as a price-taker: the size of its power system and the level of interconnection with neighbouring countries are such that it has only a very limited influence on market clearing prices. As a consequence, the cannibalisation effect (the fact that further investments in solar PV tend to decrease market prices around midday and, as a consequence, to decrease the attractiveness of solar PV) is found to only appear for unrealistic shares of solar PV. The same conclusion has been reached for wind power. More critically, this means that a credible scenarisation of the evolution of the European power system markets should be one of the central elements of any analysis of the future of the Swiss power sector.

This study is based on a number of assumptions. As is the case of all modelling exercises, changing some of these can have a material impact on the results and the conclusions. The most important category of assumptions that should be closely monitored and regularly updated when dimensioning support levels is the capital expenditure (investment costs). In this study, we have assumed, in the absence of cost curves for Switzerland, a single investment cost per technology. In reality, different projects have different costs (e.g. due to location, grid connection costs, choice of components, etc.). Adopting cost curves that describe how more expensive projects become as one gradually exploits the best options would be a direction for future research, and could lead to interesting results in terms of optimal portfolio of technologies and, potentially, optimal localisation of these technologies on the Swiss power grid.

Other assumptions that can have an impact on the results are listed below. However, the conclusions presented herein should not be significantly impacted by these assumptions:

- We have assumed that markets are coupled over the whole of Europe. Although Switzerland and its neighbours are currently coupled in the intraday markets, this situation could change in the future.
- We have only considered the revenues generated by selling electricity on the energy markets. Considering the revenues from the provision of ancillary services could impact the profitability of the considered technologies, in particular of hydropower.
- Grid connection costs are outside the scope of this study.
- The impact of balancing responsibility are not presented in this study. In order to fully capture this impact a more detailed representation of the units would be necessary, as imbalances could be compensated for through an optimal portfolio management. Furthermore, the impact of balancing responsibility for RES producers depends on the details of the design of the financial settlement of imbalances (for which the RES producers can either be charged by or paid by the TSO, depending on the direction of their imbalance compared to the imbalance price area imbalance).
- We have not considered regional cooperation mechanisms for RES support. Such mechanisms would lead to a different distribution of RES generation in the cooperating countries as the best potentials would be exploited first.

Directions for future research

The following directions for future research have been identified during this project:

- An explicit representation of all market timeframes (including how positions are refined as market participants obtain more information due to the reduction of forecast errors) could be exploited, in particular to investigate the impact of bidding strategies.
- The recent decline of RES costs advocate for an analysis of the technical and economic feasibility of a power system with more RES that the one considered in this study. A joint optimisation of RES installed capacities and flexibility solutions (network, demand-response, storage, mid-merit and peak thermal generation) would have a high value for policy makers.
- A multi-energy approach to the optimisation of the Swiss energy system would be valuable, as it could detect and exploit synergies between the electricity, gas and heat systems.
- An analysis of the dynamic efficiency of the RES support schemes (i.e. the impact of the support on the gradual price decline of the technologies) would be interesting, as different technologies are likely to behave differently (since the dynamic efficiency is in particular linked to the development of a local industrial expertise). This could be coupled with a dynamic analysis of the trajectory of investment decisions between 2020 and 2050.

7. Appendix – Demand and RES data generation in METIS

This section describes the approach for the construction of climatic scenarios used in the METIS project

a. Overall approach for climatic scenarios

To be able to simulate precisely the power dispatch throughout Europe, it is crucial to use consistent weather data. For this reason, correlated RES generation data were integrated in METIS, as represented in Figure 45.

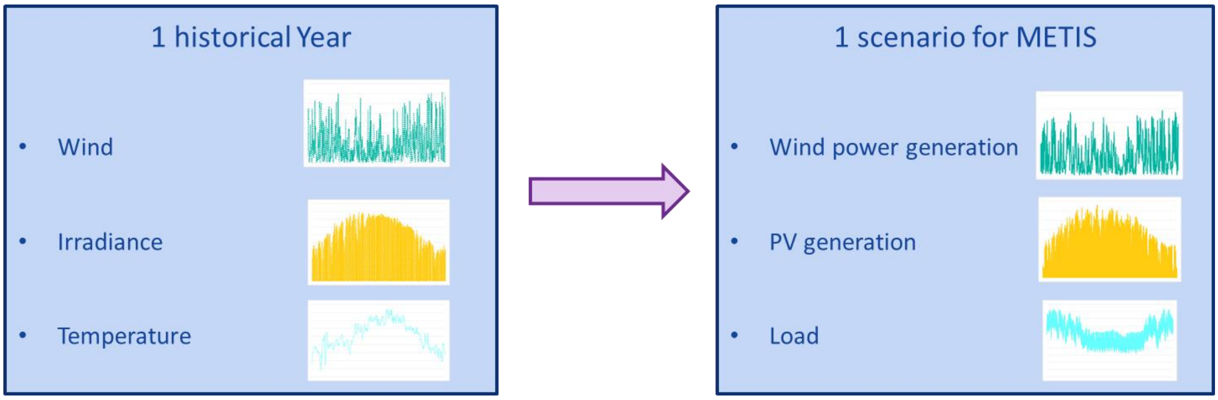


Figure 45. Correlated RES generation in METIS: for each year of weather data, one corresponding scenario is built.

The following paragraphs describe the methodology which was used to build the correlated demand time series and RES generation.

RES generation and demand forecasts have also been generated for the Power Market Module and for reserve sizing. The methodology for its computation is described in detail in *METIS Technical Note T2.*

b. Demand profiles

Temperature sensitivity and demand modelling

The objective is to generate fifty hourly scenarios of demand for each country by means of a statistical model fitted to the following data sources:

- **historical daily temperature** data from years 1965 to 2014 for all countries from the European Climate Assessment & Dataset project (ECA), see [19].
- **hourly demand data** projections for 2030 provided by ENTSO-E TYNDP 2014[34] visions 1 and 3.

In this regard, each demand scenario is modelled as the sum of a thermo-sensitive component and the non-thermo-sensitive one. The thermo-sensitive component is computed by using a piecewise linear model. This model is set up with one threshold and two slopes[35] and calibrated

[34] Data is given as hourly time series for one year and average seasonal temperatures.
[35] The use of two slopes - one slope associated to low temperatures and one slope associated to high temperatures allows for applying the same approach for each country, with the same number of parameters, although three slopes could have been used for countries with both heating and cooling gradients.

by getting recourse to a *Multivariate Adaptive Regression Splines* method[36] that involves the computation of temperature gradients (MW of demand increase per °C increase) for each country.

As depicted in Figure 46 for Spain, the temperature scenarios of each country are used to compute the thermo-sensitive part of demand scenarios by using the country temperature gradients obtained via the aforementioned load-temperature sensitivity analysis. Then, the thermo-sensitive and non-thermo-sensitive parts demand are added so as to complete the generation of the country's demand scenarios.

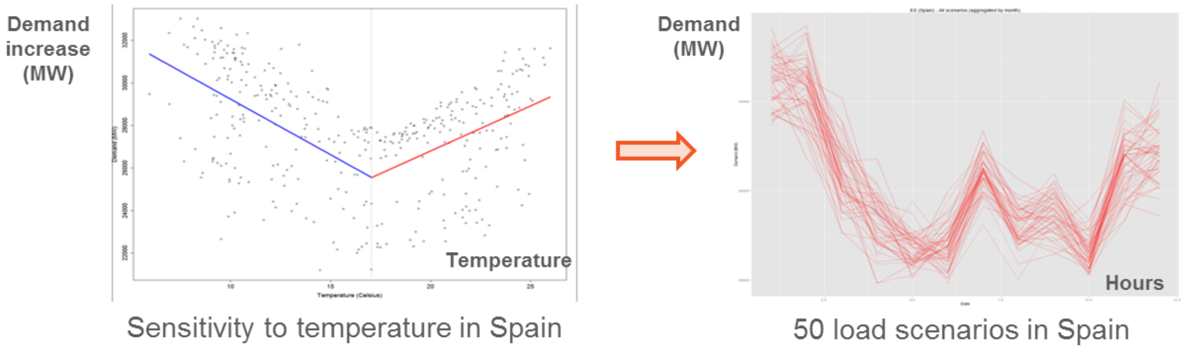


Figure 46. Two gradients and one threshold accounting for heating and cooling effects on Spain demand

c. RES generation profiles

Generation of solar and onshore wind power profiles

Generation of ten historical annual profiles for wind power and solar power has been performed by a model developed by IAEW. The model uses historical meteorological data, units' power curves and historical generation data as input parameters to determine RES generation profiles and calibrate the results for each region in the models scope.

The methodology is depicted in Figure 47.

[36] See [20] for the method and [21] for its R implementation.

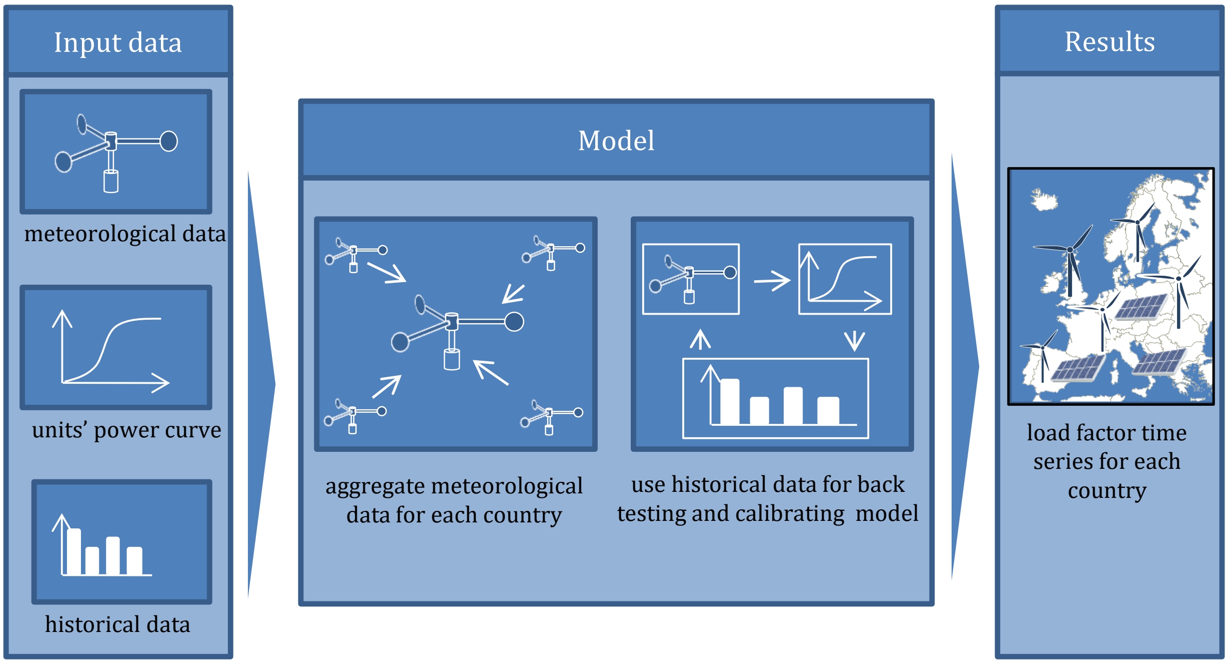


Figure 47. RES generation profiles - Methodology

Input Data

Meteorological Data

The delivered time series of renewable feed-ins are based on fundamental wind, solar and temperature time series for 10 years (2001 to 2010) on a detailed regional level derived from the ERA-Interim data provided by Meteo Group Germany GmbH. From ERA-Interim's model, values for wind speed (m/s), global irradiation (W/m2) and temperature (°C) are derived for every third hour and interpolated to hourly values by Meteo Group. The regional resolution of the data is one hourly input series (wind, solar, temperature) on a 0.75° (longitude) times 0.75° (latitude) grid model, which ensures an adequate modelling accuracy. The regional resolution is shown in Figure 48, in which each blue dot represents one data point.

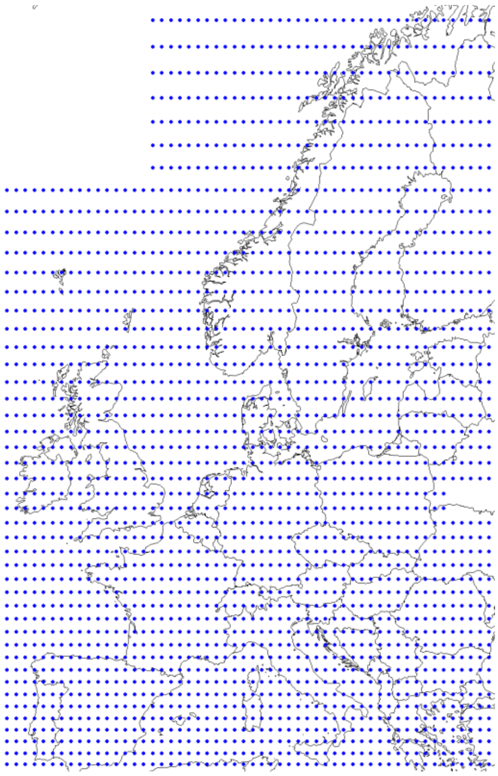


Figure 48. Regional resolution of meteorological data

Historical Data

To generate realistic time series, a calibration of the models is inevitable. Therefore information regarding the annual full load hours for wind and PV generation in each country is necessary. To derive the annual number of full load hours the installed capacities of wind and PV generation as well as the annual energy production have been investigated for each country.

In case of unavailable data the full load hours were derived based on the data of a neighbouring country. As the availability for data regarding installed wind generation capacities and generated energy is satisfying in almost every country it is rather low for information regarding PV power. Only for a few countries reasonable full load hours could be derived from historical published data. For the other country data from the Photovoltaic Geographical Information System was used instead.

Model

In first step the high-resolution meteorological data are aggregated for each country and NUTS2 region. The aggregation is thereby based on the regional distribution of wind and PV capacities. The required distribution of wind and PV generation capacities is extracted from different databases and is aggregated at high voltage network nodes. In countries with no available information a uniform distribution is assumed.

Each high voltage network node gets the nearest meteorological data point assigned to and the data is weighted with the installed capacity at the network node. Thereby the wind-speed is weighted by the installed wind generation capacity whereas global irradiation and temperature are weighted with the installed PV generation capacity. The weighted time series for all nodes in each region are aggregated and divided by the overall installed wind respectively PV capacities. Subsequently, it is necessary to calibrate the generation models for each country by scaling the meteorological data accordingly. The process of calibration is display in Figure 49.

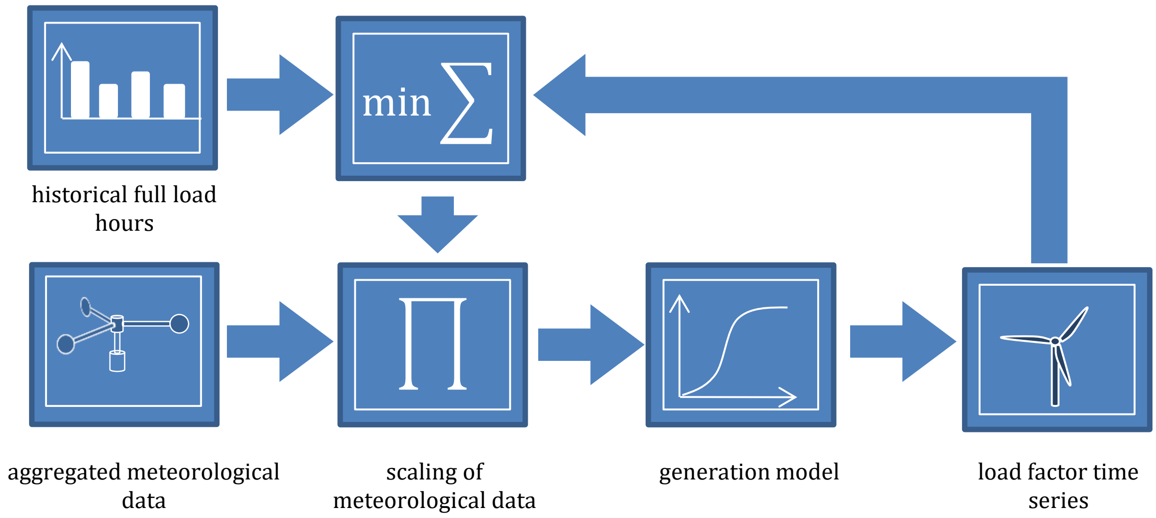


Figure 49. RES generation profile - Model calibration

The meteorological data is fed into generation models for PV and wind generation. The resulting load factor time series are compared with the historical full load hours for the specific country and the deviation between load factor time series and the historic full load hours in each year *i* is to be minimized by scaling the meteorological data accordingly. In this minimization the annual deviation between time series full load hours (*FLH*) and historical data is weighted with the installed capacity (*IC*) in the specific year according to the following formula.

$$\min \sum_{i=1}^{10} (FLH_{i,time\ series} - FLH_{i,historical\ data}) \cdot IC_i$$

The scaling factors are chosen independently for wind speed and global irradiation and are individual for each country.

The resulting full load hours for both wind and PV for several countries are shown in Figure 50. Whereas the PV full load hours per year are not changing significantly from one year to the next, the resulting full load hours from wind generation vary considerably.

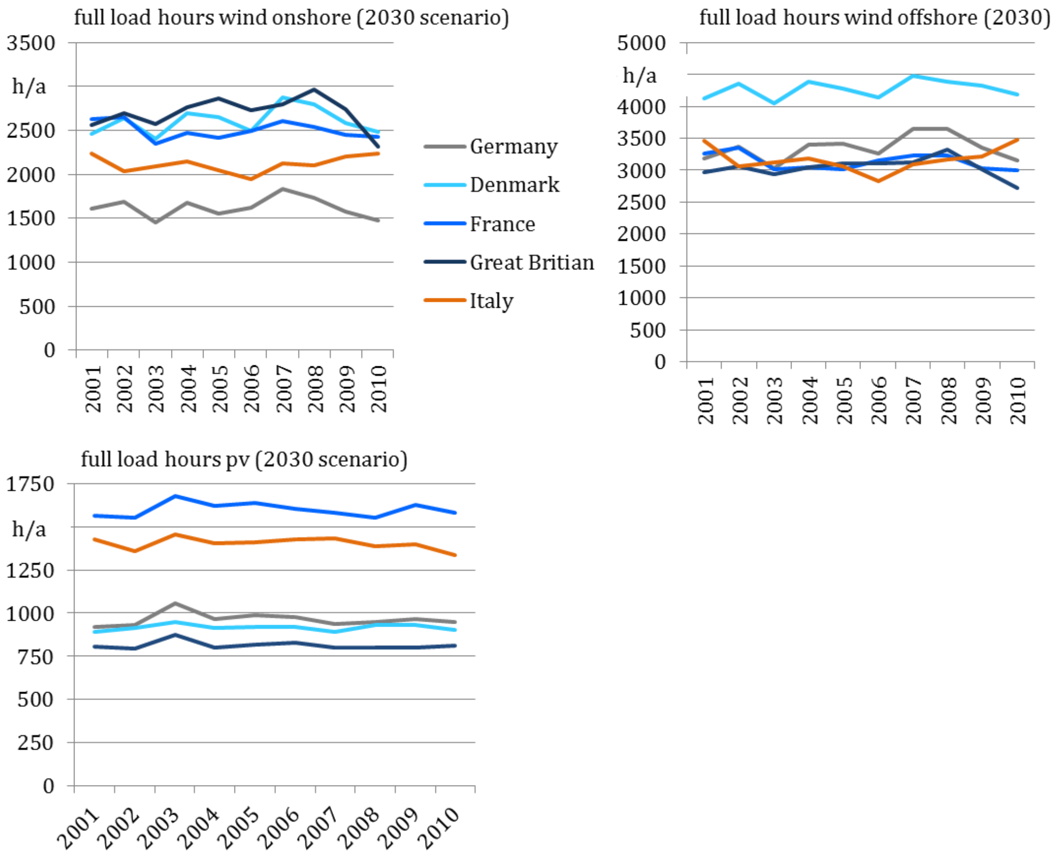


Figure 50. Wind and PV full load hours per year

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